ENERGY REPORT TO THE REGULATORY FLEXIBILITY COMMITTEE OF THE INDIANA GENERAL ASSEMBLY

By the Indiana Utility Regulatory Commission
September 2000

Chairman William D. McCarty

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1. PURPOSE AND SCOPE OF THE REPORT

This report is intended to satisfy the requirements of I.C. 8-1-2.5-9(b). The report outlines the status of competition in the Indiana energy utility industries, both electric and gas. The report reviews the activities of the energy industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 1999 Energy Report.[1] It also examines competition initiatives at the state and federal levels.

[1] Energy Report, Indiana Utility Regulatory Commission, September 1999.

2. EXCUTIVE SUMMARY

This Executive Summary will not attempt to discuss every item covered in the body of the 2000 Energy Report. Instead, the Executive Summary will highlight new or significant events detailed in the report. The reader is encouraged to review the body of this report or the 1999 Energy Report for items of interest not presented in the Executive Summary.

A. Summary of Year 2000 Computer Problems

As part of the state and national efforts to address the potential Y2K computer problem, on November 12, 1998, the Indiana Utility Regulatory Commission initiated an investigation into the problem as it related to Indiana utilities' ability to deliver service to their customers. The investigation included electric, gas, telecommunication and water/sewer utilities.

While the Commission was confident that the proactive efforts made any Y2K problems unlikely to happen, we wanted to make sure that any problems that did occur could be quickly discovered and communicated. The IURC's offices were staffed from December 31 through the morning of January 1, 2000. Additionally, IURC staff, along with personnel from many other state and federal agencies, were on duty in the State Emergency Management Agency operating room from about 6:00 PM on December 31, 1999 through about 3:00 PM on January 1, 2000.

No Y2K utility outages were encountered. **The Commission would like to thank the utilities, as well as all other participating local, state and federal agencies, for their unprecedented cooperation and efforts to make Y2K a "non-event."**

B. Cause No. 41363, IURC Investigation into FAC Proceedings

On January 20, 1999, the IURC issued an Order initiating a generic fuel adjustment cost charge ("FAC") investigation. The impetus for the investigation was the escalation in spot market purchase power prices observed in June 1998. The purpose of the investigation was to determine whether existing FAC procedures were sufficient to define the appropriate treatment of current wholesale purchase power transactions. On August 18, 1999, the Commission issued an Order in the cause. The Commission found that the costs of purchase power up to and including a certain level, known as a benchmark, would be fuel costs included in purchased power and therefore recoverable through the FAC. Fuel adjustment proceedings subsequent to the Commission's order became more litigious as parties disputed the meaning of the benchmark.

On July 19, 2000, the Commission approved a settlement agreement regarding many of the disputed issues concerning the benchmark and the costs of purchased power. The parties to the settlement agreement included Indianapolis Power & Light, Southern Indiana Gas & Electric Company, Northern Indiana Public Service Company and the Office of Utility Consumer Counselor (OUCC). Key components of the settlement agreement include:

- Full recovery (up to $77.50 per MWh) of economy purchase power costs through the FAC.
- Recovery through the FAC of 85% of the cost of power purchased to replace the power lost due to a generating unit being forced out of service or the available output being decreased for certain environmental reasons, up to a maximum of $700 per MWh.
- The OUCC agreed to withdraw its appeal of Order issued in Cause No. 41363.
- The settlement agreement provisions would apply to utility power purchases made for the months of July, August and September 2000.
- The parties agreed to attempt to negotiate a comprehensive ongoing mechanism for the recovery of purchase power costs.

C. PSI Energy Purchased Power Tracker

On May 28, 1999, PSI Energy filed a petition seeking approval of a purchased power tracker to provide for recovery of certain wholesale power purchase costs. A "tracker" is a regulatory mechanism that allows a utility to pass on to its retail customers, on a periodic basis, changes in the costs of specific expenses outside the context of a general rate case.

PSI's proposal sought approval to track the costs of certain pre-arranged power purchases made to meet retail native load peak requirements for the months of June through September for 1999, 2000 and 2001.

On May 31, 2000, the Commission issued an interim Order. The Commission approved the tracker, as proposed by PSI and modified with a mitigation credit recommended by the OUCC, only for purchases made for the summer of 2000. The Commission expressed concerns about the tracker and wanted to gather experience before approving it for a longer period of time. The Commission instructed PSI to file a petition and supporting testimony in a subdocket prior to approving a specific dollar amount for the summer of 2000 power purchases. On June 15, 2000, PSI made such a filing. This case is still pending.

D. Electric Industry Related Regional Developments

1. FERC Order 2000

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000 which encouraged all transmission owners to voluntarily join regional transmission organizations (RTOs). It defined an RTO as "an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region." The FERC decided the formation of appropriate RTOs was the best way to improve both the operational and reliability management of the transmission grid and also eliminate the ability of vertically integrated utilities to discriminate in the provision of transmission services.

The order required all public utilities that own, operate or control interstate transmission facilities to file with the FERC by October 15, 2000, a proposal for an RTO to be operational by December 15,

2001. Alternatively, utilities can file a description of efforts to participate in an RTO, obstacles to participation and any plans to work toward RTO participation. A public utility that is a member of an existing transmission entity approved by FERC under principles established in Order No. 888, must make a filing no later than January 15, 2001. The filing must explain how the existing transmission entity will comply with the minimum characteristics and functions established in Order No. 2000.

The FERC also established a collaborative process to assist in the voluntary formation ofRTOs. The collaborative workshop for the Midwest region was held in Cincinnati on March 1-2, 2000. The IURC, in conjunction with the Ohio and Michigan commissions, has sponsored meetings to continue the collaborative process. These meetings have included the Indiana Office of the Utility Consumer Counselor, other state commissions, consumer advocates from other affected states, representatives of the Midwest ISO and the Alliance RTO, consumer groups and other interested parties. At the request of the state commissions, the Federal Energy Regulatory Commission staff has been facilitating the discussions.

2. Midwest Independent System Operator (MISO)

The MISO will have primary responsibility for ensuring the reliable and economic operation of the electric transmission system in vast portions of the Midwest once it becomes fully operational. The MISO consists of a diverse group of large and small utilities that include investor-owned, rural electric cooperative and municipally owned systems.

The Midwest ISO has taken several significant steps to extend its membership and geographic scope in the last year. In November 1999, the MISO and the Mid-America Interconnected Network, Inc. (MAIN) signed an agreement that gave the MISO certain operation responsibilities for the MAIN transmission system. MAIN includes portions of Illinois, Michigan, Missouri and Wisconsin.

In December 1999, the MISO and the Mid-Continent Area Power Pool (MAPP) approved a Memorandum of Understanding to pursue a combination of the two organizations. The MAPP is an association of more than 90 electric utilities and other electric industry participants serving the following states and Canadian provinces: Minnesota, Iowa, Nebraska, North Dakota, and Manitoba and portions of Missouri, Kansas, Wisconsin, Montana and South Dakota.

The MISO has begun construction of its $64 million headquarters and control center in the city of Carmel, Indiana. When fully operational the MISO will provide approximately 200 high-pay, high-tech jobs to the area. The control center is scheduled to begin initial operations in June 2001 and to be fully operational by the end of 2001.

3. The Alliance Regional Transmission Organization

On June 3, 1999, American Electric Power, Consumers Energy, Detroit Edison, First Energy and Virginia Electric and Power (collectively the Alliance Companies) filed a request with the FERC to approve the Alliance Regional Transmission Organization. On July 7, 1999, the IURC fileda protest and a request to intervene at the FERC.

On December 20, 1999, the FERC issued its Conditional Acceptance Order authorizing the Alliance Companies to transfer ownership or functional control of their jurisdictional transmission facilities to the Alliance RTO provided that reforms were made in the structure and function of the organization and that certain elements of the proposal were explained and clarified.

On February 17, 2000, the Alliance Companies submitted its Compliance Filing to the FERC responding to some of the requirements imposed in the Alliance order. On March 21, 2000, the IURC filed with the FERC a Protest to the Compliance Filing.

On May 18, 2000, the FERC issued its order on the Alliance Companies Compliance Filing. FERC found that the compliance filing did not fully satisfy the requirements of the Alliance Order. Further filings were directed to satisfy these requirements, but the Alliance Companies were permitted to move forward with their proposal.

In a June 13, 2000 letter to the FERC, the Alliance companies said they were in the process of preparing another compliance filing and planned to submit the completed filing as soon as feasible

E. Electric and Gas Mergers in Indiana

1. AEP – CSW Merger

On May 31, 2000, the FERC issued a final order approving the American Electric Power and Central and South West Corporation merger. On June 15, 2000, the merger was completed.

2. Indiana Energy, Inc. (IEI) – SIGCORP, Inc. Merger

On June 14, 1999, IEI and SIGCORP, Inc. announced an agreement to combine into a new holding company called Vectren Corporation. The companies filed a Joint Petition with the IURC for approval, to the extent required, of a proposed merger of equals on June 17, 1999, which is still pending with evidentiary hearings scheduled for October 20 and 23, 2000.

On August 13, 1999, Indiana Energy/SIGCORP filed an application for merger approval with the Federal Energy Regulatory Commission, which approved the merger and formation of Vectren on December 20, 1999.

3. NiSource – Columbia Energy Merger

On February 28, 2000, NiSource, the parent company of Northern Indiana Public Service Company, announced its merger with Columbia Energy Group. To date the companies have received approvals from all necessary regulatory agencies except the Securities and Exchange Commission. The merger is expected to be completed by the end of 2000.

4. IPALCO – AES Merger

On July 17, 2000, AES Corporation and IPALCO Enterprises announced an agreement whereby AES would acquire IPALCO Enterprises, Inc. for $25.00 per share in a stock-for-stock transaction.

The proposed merger must be approved by IPALCO shareholders and several regulatory agencies, including the Federal Energy Regulatory Commission and the Securities and Exchange Commission. AES and IPALCO have yet to make any of the necessary regulatory filings, but the parties anticipate receiving regulatory approvals and closing the transaction by early 2001.

F. Recent Increases in Indiana Gas Prices

Gas prices are projected to be higher for the upcoming heating season. According to the American Gas Association (AGA), a number of factors are responsible for the increase in the cost of natural gas. Because the previous two winters were mild and gas consumption was low, reduced demand lowered prices. The average retail cost of gas fell 29 percent in 1998 from the previous year, which caused gas exploration and production companies to stop drilling for a nine-month period (August 1998 to April 1999). Prices for May 1999 rose, and new drilling and development resumed. Increases in drilling indicators point to an expectation that domestic production capability will remain strong in the foreseeable future and that price signals will encourage additional drilling.

Even with the increase in gas exploration and production, it still takes six to nine months before gas begins to move in interstate commerce, and eighteen months for offshore rigs. Because of the time lag between increased drilling, getting gas to market and a significant price response, it is unlikely that price reductions from increased drilling will be reflected on customer bills this winter.

Another factor contributing to the high cost of natural gas is the increase in demand by all sectors using gas. Ongoing economic growth continues to increase gas use by factories, other industrial customers and cogenerators, which consume about 40 percent of natural gas in the United States. High oil prices have prevented many factories and electricity generators from switching from natural gas to fuel oil. Gas-fired electricity generation is a small but fast growing component of gas demand.

A key variable affecting residential gas bills is the weather. The previous two winters were mild, and a return to normal weather would increase consumer heating bills even if gas prices were unchanged from last year's low levels. Significantly higher heating bills will result if projected increases in gas commodity prices are combined with higher gas consumption due to a return to normal, but colder, weather.

G. Recent Developments in Natural Gas

1. Citizens Gas and Coke Alternative Regulatory Plan

Citizen's Gas and Coke Utility (Citizen's) filed a petition with the Commission on November 23, 1999, requesting authority to implement an alternative regulatory plan. Currently, the utility is actively involved in settlement negotiations with the OUCC.

Citizen's provides natural gas service to 255,549 residential, commercial and industrial customers in and around Marion County, Indiana. Implementation of its proposal will prospectively result in all customers being able to choose their gas supplier, with Citizens remaining one of the supplier choices.

2. FERC Order 637

FERC issued Order 637 on February 9, 2000, in response to its Notice of Proposed Rulemaking,[2] which sought comment on a variety of fundamental changes to current regulatory methods, and its Notice of Inquiry,[3] which questioned whether changes in cost-of-service rate methodologies should be implemented.

The Order is designed to provide new economic opportunities and improve efficiencies within the gas transportation marketplace, while simultaneously protecting captive customers from the exercise of market power. The rule revises aspects of the current regulatory model without making fundamental changes to it.

On May, 19, 2000, FERC issued Order 637-A, which responded to the requests for rehearing and clarification that accompanied the issuance of Order 637. For the most part, FERC reaffirmed Order 637. To the extent it granted clarifications or made changes, it focused on expanding the rights of shippers on pipelines and reduced the ability of pipelines' tariffs to define the service relationship with shippers.

FERC has scheduled several public staff conferences that will permit an industry-wide discussion of issues affecting natural gas transportation policies and the role such natural gas transportation services play in energy markets in general.

H. Reliability Concerns

1. IURC Investigation and Review of Electric-System Reliability

During the summer of 1999, throughout the Midwest, generation capacity was stretched to its limits due to successive days of high temperatures and humidity. Following this event, the Commission

[2] Regulation of Short-Term Natural Gas Transportation Services, Notice of Proposed Rulemaking, Docket No. RM 98-10-000, 63 FR 42982 (Aug. 11, 1998), FERC Stats. & Regs. Proposed Regulations (1988-1998) 32,533 (July 29, 1998).

[3] Regulation of Interstate Natural Gas Transportation Services, Notice of Inquiry, Docket No. RM 98-12-000, 63 FR 42973, IV FERC Stats. & Regs. Notices 35,533 (July 29, 1998).

staff began an informal process to meet with each of Indiana's electric utilities to discuss their experiences during the heat wave. The Commission staff produced a report detailing the utilities' experiences during the heat wave.[4]

In the spring of 2000, the IURC issued a survey to determine how the utilities were preparing for the summer peaking season. These surveys were followed-up by a public meeting that allowed the utilities to describe the preparations for summer 2000 directly to the commissioners and staff.

As a result of the information learned through IURC efforts plus other factors, such as recent actions by the Environmental Protection Agency and federal courts and the construction of non-utility owned generation facilities, the Commission initiated an investigation into all matters affecting the adequacy and reliability of electric service to Indiana retail customers.[5] The initiating order stated:

> One goal of this proceeding is to better inform the Commission of the complex issues associated with maintaining reliable electric service, but another is to increase the public awareness of these complexities. The ultimate objective of this proceeding is to develop policies and initiatives to promote and maintain adequate and reliable electric service. It is our hope that this proceeding will allow the parties to have interactive discussion that will be one of the tools this Commission may use in the future as it evaluates the energy needs of our State.

As part of the proceeding, the Commission scheduled seven workshops to address specific reliability topics. The workshops are currently ongoing and should be complete by the end of 2000.

I. Merchant Power Plants

Since last year's Energy Report, the IURC has received 13 new petitions relating to the siting and construction of merchant plants.[6] Of those, the Commission has approved two, Whiting Clean Energy in Whiting and DPL Energy in Wells County. Three petitioners, LS Power in Columbus, SIGECO in Mount Vernon, and Duke DeSoto in Delaware County, withdrew their petitions and were dismissed this year. Nine petitions are currently under review before the Commission, including eight new petitions and one still pending from 1999.

Five petitions for peaking units and merchant plants were approved last year and all five are in commercial operation. Currently, total merchant plant capacity operating in Indiana is approximately 1550 MW.

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[4] This report can be found on the IURC website at www.ai.org/iurc/energy/papers.html.

[5] Cause No. 41736, issued May 10, 2000.

[6] Cause Nos. 41530, 41545, 41569, 41580, 41590, 41599, 41685, 41749, 41753, 41757, 41803, 41804.

J. EPA Actions

For the past few years, The U.S. Environmental Protection Agency (EPA) has targeted electric utility nitrogen oxide emissions as a way of reducing smog in the eastern half of the nation and in making the air cleaner in general. In March of 2000, the EPA initiative known as the NOX SIP Call was largely upheld in federal court. This initiative will require an 85% reduction of utility NOX emissions starting in May of 2003. The cost for Indiana electric utilities is not known precisely, but will be in the hundreds of millions of dollars.

Because of the relatively short amount of time available to install a large amount of retrofit equipment, there is a concern about electricity reliability. Installing the pollution control equipment will require large generating units to be shut down for more weeks than normal in the spring and fall. To the extent it is available, new merchant plant capacity in the region will help to alleviate this potential reliability risk.

K. Federal Legislative Update

This year, over 20 restructuring bills were introduced in Congress, but only H.R. 2944 went so far as to pass out of subcommittee. S. 2071, a strict reliability bill actually passed out of the Senate this summer, but no further action has been taken by the House.

3. SUMMARY OF YEAR 2000 COMPUTER PROBLEMS

As part of the state and national efforts to address the potential Y2K computer problem, on November 12, 1998, the Indiana Utility Regulatory Commission (IURC) initiated an investigation (Cause No. 41327) into the problem as it related to Indiana utilities' ability to deliver service to their customers. The investigation included electric, gas, telecommunications and water/sewer utilities. It was the Commission's plan to undertake a dual role that would protect the public interest, while addressing the needs of utilities as well through a collaborative process.

During the course of the investigation, the IURC issued and reviewed utility Y2K readiness surveys (including contingency plans) to assess the utilities' efforts and progress in addressing the Y2K problem. The Commission also hosted two workshops to facilitate the exchange of information on Y2K readiness.

While we believed that our efforts and the efforts of those we regulate made any Y2K problems highly unlikely to happen, we wanted to make sure that any problems that did happen could be quickly discovered and communicated. The IURC's offices were staffed from about 8:00 AM on December 31, 1999 to 6:00 AM on January 1, 2000. Additionally, IURC staff, along with staff from many other state and federal agencies, were on duty in the SEMA (State Emergency Management Agency) operations room from about 6:00 PM on December 31, 1999 to about 3:00 PM on January 1, 2000.

No Y2K utility outages or problems were encountered. There were a few "normal" electrical outages reported during the period, but the outages reported were actually much less than historically reported over the New Years' Holiday. **The Commission would like to thank the utilities, as well as all other participating local, state and federal agencies, for their unprecedented cooperation and efforts to make Y2K a "non-event".**

4. INDIANA'S ENERGY MARKETS

— Review of the Electricity Industry —

Industry Structure

Electric utilities in the United States are categorized by their type of ownership--government (federal and municipal), cooperative and investor-owned. The utilities have the same goal, which is to provide reliable electric service at reasonable cost to their customers, but distinct corporate structures result in different methods employed by the utilities to meet this goal. Because of the differences in utility structure, government policy does not affect each type of utility in the same manner.

Investor-Owned Utilities

The type of utility that is most significant in terms of generation and customers served is the investor-owned (IOU). Five major investor-owned utilities operate within the state: Indianapolis Power & Light (IPL), Indiana Michigan Power (I&M), Northern Indiana Public Service (NIPSCO), PSI Energy (PSI), and Southern Indiana Gas & Electric (SIGECO). IOUs are for-profit enterprises funded by debt and equity. IOUs are judged by the same standards as any publicly held company; investor services rate their bond issues and make recommendations on stock purchases. Most IOUs are vertically integrated, meaning they own facilities for generation, transmission and distribution.

All of Indiana's IOUs are owned by holding companies. Holding companies are entities that own enough stock in another company to influence management of the held company. Two of the state's IOUs, PSI Energy and Indiana Michigan Power, are subsidiaries of multi-state holding companies (Cinergy and American Electric Power, respectively). Multi-state holding companies are required under the Public Utility Holding Company Act (PUHCA) to register with the Securities and Exchange Commission (SEC), and the SEC monitors their actions to ensure compliance with PUHCA regulations.

Table 1 presents generation and sales information for Indiana's five major IOUs. The "Sales for Resale" illustrates that IOUs are typically able to generate enough power for their own requirements and produce power for sale in the wholesale market.

Table 1: Investor-Owned Utility Statistics – 1999

UTILITY	CAPACITY (MW)	TOTAL SALES (GWh)	SALES FOR RESALE (GWh)	RESIDENTIAL SALES (GWh)	COMMERCIAL SALES (GWh)	INDUSTRIAL SALES (GWh)
I&M	4,443	25,920	7,581	5,351	4,668	8,236
IPL	2,968	15,850	2,001	4,570	1,952	7,254
PSI	5,968	55,072	28,971	7,872	6,655	11,508
NIPSCO	3,392	18,215	2,587	2,997	3,294	9,198
SIGECO	1,236	6,941	1,830	1,372	1,304	2,416

Source: 1999 FERC Form 1 and 1999 Shareholder Reports

Municipal Utilities

There are 79 municipally owned electric utilities in Indiana. As of August 2000, twenty-eight municipal utilities remain under IURC jurisdiction for rate regulation. Municipals are organized as nonprofit local government agencies and pay no taxes or dividends, although revenue can be turned over to the general city fund if the city elects to do so. Municipals raise capital through the issuance of tax-free bonds.

Municipal utilities typically own very little, if any, generating capacity; they purchase electricity from other sources and resell it to their retail customers. The reseller status limits a municipal's need to raise large amounts of capital because it does not invest in capital-intensive generation. The advantages of a municipal utility include the local government receiving revenue from earnings, and generally lower electricity rates for the municipality due to the low capital investment and tax-exempt status.

Many municipals in the state are members of the Indiana Municipal Power Agency (IMPA). IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA is a political subdivision of the state under Indiana Code 8-1-2.2 and is not subject to state or federal income taxes.

IMPA owns generating facilities and has member-dedicated generation. It also holds ownership interest in two units, Gibson 5 (co-owned with PSI and Wabash Valley Power Association) and Trimble County 1 (co-owned with Louisville Gas and Electric and the Illinois Municipal Electric Agency). It meets the rest of its members' needs through purchased power.

Cooperatives

Another type of nonprofit electric utility is the cooperative. Forty-three distribution co-ops exist in Indiana. As of August 2000, seven electric utility cooperatives remain under Commission jurisdiction for rate regulation. Co-ops were originally formed as a result of the Rural Electrification Act of 1936 to bring electric service to rural areas. Co-ops were usually formed by farmers to build lines and then, similar to municipal utilities, purchase electricity from private companies at wholesale rather than owning and operating generation facilities.

Although co-ops were created to distribute power, since the 1960s over 50 generating and transmission (G & T) cooperatives have been formed nationally to supply power to distribution co-ops. Within Indiana, there are two G & T co-ops: Hoosier Energy (HE) and Wabash Valley Power Association (WVPA). These G & T co-ops serve as coordinators of bulk power supplies and transmission services for their members, as IMPA does for municipals.

Table 2 illustrates the proportion of power purchases to generation for IMPA and the generation and transmission cooperatives, Hoosier Energy and Wabash Valley Power Association. The table illustrates that Hoosier Energy owns a significant amount of generating capacity compared to Wabash Valley.

Table 2: IMPA/G&T Cooperative Statistics – 1999

UTILITY	CAPACITY (MW)	GENERATION (GWh)	PURCHASES (GWh)	SALES (GWh)
IMPA	555	NA	NA	4,510
Hoosier Energy	1,266	8,901	1,874	10,058
Wabash Valley	156	898	5,063	5,611

Source: 1999 Annual Reports.
"Losses" account for the difference between the sum of generation and purchases minus sales.

Indiana Electricity Prices

Table 3 presents a comparison of average electric utility revenue per kWh by state for 1999. It is important to note Indiana's position near the bottom of the revenue per kWh rankings, indicating Indiana is a low-cost state. The cheaper western states have the advantage of hydropower and abundant coal reserves, as does Kentucky. Indiana's favorable ranking comes not only from its coal reserves, but also from relatively little utility investment in expensive nuclear power. States shown in bold type, including Indiana, have not restructured their electric utility industry at this point in time although most of these states are closely monitoring the restructuring activities in other states.

For more detailed revenue, sales and market share information for Indiana utilities, please see Appendix A.

Table 3: Average Revenue, Cents Per kWh by Sector and State – 1999 (Ranked from Highest to Lowest)

State	Residential	Commercial	Industrial	Other	Total Average
New Hampshire	13.9	11.4	9.3	13.1	11.9
Hawaii	13.2	12.1	9.1	11.9	11.2
Vermont	12.4	11.4	8.0	17.6	10.9
Maine	13.1	11.6	7.2	24.6	10.6
New York	13.1	10.7	4.6	8.4	10.1
Connecticut	11.4	9.6	7.3	11.1	9.9
New Jersey	11.1	9.8	7.8	17.4	9.9
Alaska	10.9	9.1	7.2	13.7	9.7
Rhode Island	10.9	9.2	7.3	12.4	9.6
Massachusetts	10.1	8.5	7.4	12.8	8.9
California	10.4	8.3	5.6	5.1	8.2
Michigan	8.5	7.8	5.0	10.5	7.1
Florida	8.0	6.5	4.8	6.7	7.0
New Mexico	8.7	7.8	4.3	6.1	6.7
Arizona	7.8	6.8	5.1	4.0	6.6
Delaware	8.3	6.7	4.5	13.7	6.6
Pennsylvania	8.5	6.8	4.4	10.7	6.6
District of Columbia	7.0	6.5	4.1	6.7	6.5
Illinois	8.0	7.0	4.7	6.2	6.5
US AVERAGE	7.8	7.0	4.2	6.5	6.4
North Carolina	7.7	6.2	4.3	6.8	6.3
Maryland	7.5	5.9	3.9	8.4	6.2
South Dakota	7.0	6.4	4.4	4.6	6.2
Ohio	8.0	7.6	4.1	6.1	6.1
Colorado	7.3	5.5	4.3	7.7	5.9
Kansas	7.2	6.1	4.4	9.8	5.9
Virginia	7.0	5.5	3.8	5.1	5.8
Texas	7.1	6.8	4.0	6.6	5.8
Georgia	6.8	6.6	3.7	9.2	5.7
Nevada	7.3	6.7	4.2	3.9	5.7
Minnesota	7.0	5.9	4.4	7.4	5.6
Montana	6.6	6.0	4.0	7.2	5.6
Mississippi	6.4	6.3	4.0	7.9	5.5
North Dakota	6.0	5.8	4.2	4.3	5.5
Tennessee	6.3	6.5	4.5	8.1	5.5
Wisconsin	7.2	5.9	3.9	7.1	5.5
Iowa	7.6	6.0	3.5	6.0	5.4
South Carolina	7.3	6.2	3.5	6.2	5.4
Arkansas	6.9	5.5	3.9	6.0	5.3
Indiana	6.7	6.0	3.8	9.3	5.2
Louisiana	6.5	6.3	3.8	5.8	5.2
Missouri	6.1	5.2	3.7	5.8	5.2
Alabama	6.5	6.5	3.5	7.2	5.1
West Virginia	6.1	5.6	3.8	8.7	5.1
Nebraska	5.6	5.1	3.5	6.6	4.9
Utah	6.4	5.4	3.3	4.3	4.9
Oklahoma	6.0	4.8	3.3	4.1	4.8
Oregon	5.6	5.0	3.3	7.0	4.8
Wyoming	6.1	5.2	3.4	5.2	4.4
Washington	5.1	5.0	3.0	3.7	4.4
Idaho	5.3	4.5	2.7	4.8	4.1
Kentucky	5.3	5.2	2.7	4.5	3.8

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions." These 1999 values are preliminary.

— Recent Developments in Electricity —

Cause No. 41363, IURC Investigation into FAC Proceedings

On January 20, 1999, the IURC issued an Order initiating a generic fuel adjustment cost charge (FAC) investigation. Fuel costs include the costs of coal, natural gas, fuel oil, and uranium that power plants use to produce electricity. Additionally, if an electric utility purchased power from another utility, only a certain portion of the costs of that purchased power are considered to be fuel costs. The impetus for the investigation was the escalation in spot market purchase power prices observed in June 1998. The purpose of the generic investigation was to determine whether existing FAC procedures are sufficient to define the appropriate treatments of current wholesale purchase power transactions.

On March 10, 1999, a docket entry was issued notifying participants that the following two questions would be addressed in the proceeding:

1. Should the commission set a benchmark for the price of purchased power, which triggers a requirement that the reasonableness of the purchase in excess of the benchmark be specifically addressed in the pre-filed testimony supporting the FAC? If so, what should the benchmark be? What should be included in the supporting pre-filed testimony?

2. Should the commission require codes of conduct for those generating utilities having marketing affiliates?

On August 18, 1999, the Commission issued its order in Cause No. 41363. In that Order, the Commission found that the record was insufficient to determine that there was a need for codes of conduct and therefore did not order the codes of conduct established. It did find, however, that the costs of purchase power up to and including a certain level, known as a benchmark, would be fuel costs included in purchased power and therefore recoverable in the normal course of business through the FAC. The benchmark was set to be the specific utility's highest on-system fuel cost and the information to establish the benchmark had to be filed by each utility in the utility's next FAC application and updated annually thereafter.

Fuel adjustment proceedings subsequent to the Commission's Order in Cause No. 41363 became more litigious as the parties disputed many complex and detailed issues concerning the definition of the benchmark. The FAC procedures are designed to be summary in nature and do not lend themselves well to the resolution of complex disputed issues. The Office of Utility Consumer Counselor (OUCC) appealed the Commission's Order to the Court of Appeals.

On July 10, 2000, in IPL's normal FAC case, Cause No. 38703-FAC 48, a settlement agreement regarding many of the disputed issues concerning the benchmark and the costs of purchased power was submitted for Commission approval. The parties to the settlement agreement included IPL, Southern Indiana Gas and Electric Company, Northern Indiana Public Service Company, and the Office of Utility Consumer Counselor. Key components of the settlement agreement are as follows:

- Full recovery (up to $77.50 per MWh) of economy (those made when it is cheaper to buy power rather to generate internally) purchase power costs through the FAC.
- Recovery through the FAC of 85% of the cost of power purchased to replace the power lost due to a generating unit being forced out of service or the available output being decreased for certain environmental reasons, up to a maximum of $700 per MWh.
- The OUCC agreed to withdraw its appeal of the Commission's Order of Cause No. 41363.
- The settlement agreement would replace the Commission's Order in Cause No. 41363 for power purchased in July, August, and September 2000.
- The parties agreed to attempt to negotiate a comprehensive ongoing mechanism for the recovery of purchased power costs.

The Commission, in its July 19, 2000, Order in Cause No. 38703-FAC48, approved the settlement agreement.

PSI Energy Purchased Power Tracker

On May 28, 1999, PSI filed a petition, docketed as Cause No. 41448, seeking approval of a purchased power tracker to provide for recovery of certain wholesale power purchase costs. A "tracker" is a regulatory mechanism that allows a utility to pass on (track) to its retail customers, on a periodic basis, changes in the costs of a selected expense outside the context of a general rate case. The tracker ends up on customers' bills as a dollar per kWh added to the basic bill. The Commission has had in place, since the 1970's, a generic wholesale power cost tracker. However, the evolving wholesale electricity market has made the Commission's generic tracker impractical for some situations encountered today.

PSI's proposal was for a tracker that recovered the costs of purchased power to the extent such costs would not be recovered through normal fuel cost adjustment procedures. It sought approval of the tracker for certain pre-arranged power purchases made to meet retail native load peak requirements for the months of June through September for 1999, 2000, and 2001.

On May 31, 2000, the Commission issued its interim Order in Cause No. 41448. The Commission denied recovery of 1999 purchased power costs due to not being timely filed and insufficient evidence. The Commission approved the tracker, as proposed by PSI and as modified with a mitigation credit espoused by the Office of Utility Consumer Counselor, only for power purchases made for the summer of 2000. The Commission expressed many concerns about the tracker and wanted to gather real world experience to adequately ascertain its feasibility before approving it for a longer period of time. The Commission instructed PSI to file a petition and supporting testimony in a subdocket prior to approving a specific dollar amount for Summer 2000 power purchases. On June 15, 2000, PSI made such a filing and the case is awaiting hearings and resolution by the Commission.

Noteworthy 30-day Filings by Electric Utilities

Thirty-day filings are requests from utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. The 30-day filing process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less-costly manner than a formally docketed case. Last year, the Commission reviewed and approved for the entire utility industry more than 470 of these 30-day filings. Some of the more important electric 30-day filings approved during the last year are summarized here. The main purpose of all the filings described below is for the utility to gain the equivalent of additional generating capacity without having to physically construct generating facilities.

Indiana Michigan Power Company

On August 11, 1999, the IURC approved a rider entitled PCS Price Curtailable Service for I & M. Rider PCS allows customers to specify a maximum number of days per season they are willing to curtail. Customers may choose from three options for the maximum number of hours per curtailment. The customer also specifies the minimum price for which they are willing to curtail. RiderPCS provides for summer, fall, winter and spring seasons to recognize customer seasonal curtailment abilities and market price variations by season. Payments are based on kWh curtailed by the customer. The price the utility will pay for curtailed energy will be the greater of 80 percent of the daily on-peak into Cinergy index (a regional clearing house or hub for electricity trading); the minimum price as specified by the customer; or 3.5 cents per kWh. Additionally, I&M filed for and the IURC approved on March 1, 2000, modifications to both the PCS tariff and a somewhat similar ECS (Emergency Curtailable Service) tariff, which greatly expanded the number of customers eligible for such tariffs.

Indianapolis Power and Light Company

On April 12, 2000, the IURC approved a Standard Contract Rider No. 18, Curtailment Energy II for IPL. This rider, available to commercial and industrial customers served under Rates HL, PL, SL, or PH, compliments a similar rider (Curtailment Energy I) previously approved by the IURC. Curtailment Energy II provides for a simplified form of payment by using an energy only credit. Both Riders provide the customer a payment in exchange for having load curtailed under terms of an agreement.

On March 1, 2000, the IURC approved Standard Contract Rider No. 9, Net Metering for Customers with Solar Photovoltaic Systems for IPL. This rider provides for a two-year test of net metering for residential customers and schools that make use of solar photovoltaic (PV) systems with approved electrical connection. At times, when the customer's solar photovoltaic system produces more energy than is being provided by the utility, net metering allows the energy meter to "run backward", thus reducing the total amount of energy purchased by the customer from the utility. Each customer's system will be limited to 10 kW of solar PV capacity. Net metering is the crediting of a customer's bill for electricity by the amount of electricity that the customer may produce. In a simple approach, the dollar amount of the credit per kWh to the customer is equal to the fully bundled retail rate per kWh that the utility charges the customer. This is referred to as "equivalent rate" net metering. There may be some general equity concerns about using equivalent rate net metering for all types of customer provided generation (CPG). However, for photovoltaic CPG, the utility believed there were enough qualitative factors (e.g. the performance of small PV systems often is at its best when the utility's demand is the greatest on hot summer days) to offer this rate for the purpose of seeing if such rates and metering arrangements are worthwhile.

Standard Contract Rider No. 9 will be available to residential customers being served under Rate RS, and Elementary, Junior High, and High Schools being served under Rate SH, SL, or PL. Standard Contract Rider No. 9 will terminate two years from the date of approval, unless extended. IPL will file a report with the IURC providing the results of this experimental rate program approximately 90 days prior to the expiration date of the rider. At the same time, IPL will also advise the Commission of its intentions regarding the extension or termination of the rider.

PSI Energy, Inc.

On December 22, 1999, the IURC approved Standard Contract Rider No. 23, Peak Load Management (PLM) Program for PSI. The PLM Program will be available to customers served by PSI under Rates LLF, HLF, Special Contracts, or Standard Contract Rider No. 21-Real Time Pricing. The PLM Program is voluntary and offers customers the opportunity to reduce their electric costs by managing their electric usage during PSI's peak load periods. Under this Rider, customers will enter into a service agreement which will specify the terms and conditions under which the customer agrees to reduce usage. Customers who participate in the PLM Program will do so by choosing one of the following options:

- Reduce demand to a specified amount.
- Reduce energy usage below a baseline energy level.
- Sell the output of customer owned generation to the Utility.

Specific hours for the PLM Program service option will be agreed upon by PSI and the customer, pursuant to the service agreement. The utility will target the hours between 11:00 A.M. and 8:00 P.M., Monday through Friday, from June 1 through September 30, as the time period in which PLM Program service agreements will be implemented. Through the PLM Program, PSI hopes to provide a better means of controlling customers' summer peak demands in order to avoid installing or purchasing additional generating capacity.

Regional Developments

FERC Order 2000 to Advance the Formation of RTOs

The Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) for the formation of Regional Transmission Organizations (RTOs) on May 13, 1999. In the NOPR, the FERC raised concerns whether the traditional process of management of the transmission grid by utilities was adequate to support continued development of a competitive wholesale power market and whether vertically integrated utilities were impeding the market by continued discrimination in the provision of transmission services.

On December 20, 1999, the FERC issued Order 2000 to encourage all transmission owners to voluntarily join regional transmission organizations. The final order defined an RTO as "an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within a region." The FERC decided the formation of appropriate RTOs was the best way to improve both the operational and reliability management of the transmission grid and also eliminate the ability of vertically integrated utilities to discriminate in the provision of transmission services.

The FERC established minimum characteristics and functions that an RTO must satisfy.

Minimum Characteristics:

- Independence - The RTO must be independent of market participants (e.g., generation and transmission owners);
- Scope and Regional Configuration - The RTO must serve an appropriate region to permit the RTO to effectively perform its required functions and to support efficient non-discriminatory markets;
- Operational Authority - The RTO must have operational authority for all transmission facilities under its control; and
- Short-term Reliability - The RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates.

Minimum Functions:

- Develop and administer its own transmission tariff and employ a pricing system that will promote efficient use and expansion of transmission and generation facilities;
- Ensure the development and operation of market mechanisms to manage transmission congestion;
- Develop and implement procedures to address parallel path flow issues;
- Serve as the provider of last resort for all ancillary services;
- Operate a single OASIS (Open-Access Same-Time Information System) for all transmission under its control and independently calculate total transmission capacity and available transmission capacity;
- Monitoring of markets to identify market design flaws, market power abuses and opportunities for efficiency improvements, and propose appropriate actions;
- Plan and coordinate necessary transmission upgrades and additions; and
- Develop mechanisms to coordinate its activities with other regions.

The order required all public utilities that own, operate or control interstate transmission facilities to file with the FERC by October 15, 2000, a proposal for an RTO to be operational by December 15, 2001. Alternatively, utilities can file a description of efforts to participate in an RTO, obstacles to participation and any plans to work toward RTO participation. A public utility that is a member of an existing transmission entity approved by FERC under principles established in Order No. 888, must make a filing no later than January 15, 2001. The filing must explain how the existing transmission entity will comply with the minimum characteristics and functions established in Order No. 2000.

The FERC also established a collaborative process to assist in the voluntary formation ofRTOs. The collaborative brought together transmission owners, market participants, interest groups and government officials in an attempt to reach mutual agreement on how best to establish RTOs in their respective regions. Five regional workshop meetings were held in March and April 2000.

The collaborative workshop for the Midwest region was held in Cincinnati on March 1-2, 2000. The workshop was organized around three straw man proposals as a framework for the discussions. One straw man proposal involved a merger of the Midwest ISO and the Alliance RTO. The other two straw man proposals involved different degrees of coordination should both organizations exist. One result of the meeting was a decision to continue these important discussions. Several follow up meetings have occurred in Indianapolis, Chicago, Detroit, Columbus and Washington, D.C.

The IURC, in conjunction with the Ohio and Michigan commissions, has been a primary sponsor (host) of the meetings that have included the Indiana Office of the Utility Consumer Counselor, other state commissions, consumer advocates from other affected states, representatives of the Midwest ISO and the Alliance RTO, consumer groups and other interested parties. At the request of the state commissions, the Federal Energy Regulatory Commission staff has been facilitating the discussions.

<u>Midwest Independent System Operator (MISO)</u>

The MISO will have primary responsibility for ensuring the reliable and economic operation of the electric transmission system in vast portions of the Midwest once it becomes fully operational. The MISO is expected to begin initial operations in June 2001 and be fully operational by the end of 2001. The MISO consists of a diverse group of large and small utilities that include investor-owned, rural electric cooperative and municipally owned systems.

The MISO currently encompasses portions of twelve states: Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, North Dakota, Ohio, South Dakota, Virginia, West Virginia and Wisconsin. In addition to utilities that serve Indiana (i.e., PSI, Hoosier Energy Rural Electric Cooperative, SIGECO and Wabash Valley Power Association), the MISO includes the following transmission owning utilities: Alliant Energy (formerly Wisconsin Power & Light Company, IES Utilities, Inc., Interstate Power Company and South Beloit Water, Gas & Light Company), Ameren (formerly Union Electric of St. Louis and Central Illinois Public Service), CILCO (Central Illinois Light Company), Commonwealth Edison, Illinois Power, Louisville Gas & Electric, Madison Gas and Electric Company, Northern States Power, Southern Illinois Power Cooperative and Wisconsin Electric Power Company.

The Midwest ISO has taken several significant steps to extend its membership and geographic scope in the last year. In November 1999, the MISO and the Mid-America Interconnected Network, Inc. (MAIN) signed an agreement that gave the MISO certain operation responsibilities for the MAIN transmission system. Most MAIN transmission owners have joined the MISO. MAIN includes portions of Illinois, Michigan, Missouri and Wisconsin.

In December 1999, the MISO and the Mid-Continent Area Power Pool (MAPP) approved a Memorandum of Understanding to pursue a combination of the two organizations. The MAPP is an association of more than 90 electric utilities and other electric industry participants serving the following states and Canadian provinces: Minnesota, Iowa, Nebraska, North Dakota, and Manitoba and portions of Missouri, Kansas, Wisconsin, Montana and South Dakota.

Also in December 1999, the MISO Board of Directors approved a Letter of Agreement with the Southwest Power Pool (SPP). The letter formed the basis for negotiations seeking to combine the SPP and MISO, but negotiations were suspended when the SPP decided to pursue other options.

The MISO has begun construction of its $64 million headquarters and control center in the city of Carmel, Indiana. When fully operational, the MISO will provide approximately 200 high-paying, high-tech jobs to the area. The control center is scheduled to begin initial operations in June 2001 and to be fully operational by the end of 2001.

The Alliance Regional Transmission Organization

On June 3, 1999, American Electric Power, Consumers Energy, Detroit Edison, First Energy and Virginia Electric and Power (collectively the Alliance Companies) filed a request with the FERC to approve the Alliance Regional Transmission Organization (ARTO). On July 7, 1999, the IURC filed a protest and a request to intervene at the FERC. The IURC specifically asked the FERC to employ Alternative Dispute Resolution (ADR) to resolve some issues between the ARTO and other RTOs such as the Midwest ISO. The IURC expressed concern that the Alliance proposal did not fully comply with the eleven independent system operator principles articulated in the FERC's Order 888 and the FERC's Notice of Proposed Rulemaking (RM99-03-000) issued May 13, 1999. The IURC asserted that the Alliance proposal, at a minimum, required substantial revision.

On December 20, 1999, the FERC issued its Conditional Acceptance Order authorizing the Alliance Companies to transfer ownership or functional control of their jurisdictional transmission facilities to the Alliance RTO provided that reforms were made in the structure and function of the organization and that certain elements of the proposal were explained and clarified. Specifically, the FERC found that the Alliance RTO does not meet Order No. 888's independence standard. The FERC was concerned by numerous features of the Alliance RTO proposal, including: the Alliance Companies' ownership of up to 25% of the stock at formation; that the admission of additional utilities will increase utility control over Alliance; that the Alliance Companies can veto the addition of new members; that the Alliance Companies can veto the addition of existing facilities owned by others; that there may be substantial and controlling fiduciary responsibilities on the part of the Alliance RTO to the Alliance Companies which have not been explicitly limited. The Alliance Companies were also directed to delete the exclusive right of the Alliance Companies to remove the Board of Directors.

On February 17, 2000, the Alliance Companies submitted its compliance filing to the FERC responding to some of the requirements imposed in the Alliance order. On March 21, 2000, the IURC filed with the FERC a Protest to the Compliance Filing. The Protest stated:

> However, the IURC believes that in adding its voice to others of like views it is adding weight to the conclusion that there is a fundamental problem with what is now on the

> table respecting the large and complex proposed venture. Before us is a piecemeal approach, played close to the chest. As it stands, critical questions regarding how it - alone and in coordination with neighboring independent regional organizations - will function seamlessly and transparently have been left for the future. Moreover, the ownership, governance and commercial concerns that are specifically addressed fall short in several respects of adequately responding to the Conditional Acceptance Order.

On May 18, 2000, the FERC issued its order on the Alliance Companies Compliance Filing. FERC found that the compliance filing did not fully satisfy the requirements of the Alliance Order. Further filings were directed to satisfy these requirements, but the Alliance Companies were permitted to move forward with their proposal.

In a June 13, 2000 letter to the FERC, the Alliance companies said they were in the process of preparing another compliance filing and planned to submit the completed filing as soon as feasible.

— Mergers and Acquisitions —

Mergers are viewed with caution by federal and state regulatory agencies because the merged entity may be able to exercise increased market power resulting in noncompetitive prices, lack of product innovation and a decrease in the range and quality of service to the consumer. Mergers can also threaten state commerce by reducing job levels or draining employees from one state to another. Some mergers, however, result in substantial benefits to the shareholders, customers and employees of the merged companies. All proposed mergers or acquisitions should be objectively analyzed to identify the potential negative and positive outcomes. Traditional merger evaluation criteria are based on the need to review mergers of companies operating in a competitive industry. The energy industry, however, has a natural tendency for developing a monopoly market making it particularly critical that mergers among energy utilities undergo a thorough evaluation before final approval. It is difficult to apply traditional merger evaluation criteria when analyzing mergers among energy utility companies because some utility functions remain regulated monopolies while others are in the initial stages of transition to more competitive markets.

Prior to 1996, electric utility merger applications argued that customers would realize substantial savings due to the coordination of generating unit dispatch and other operations. In April 1996, the Federal Energy Regulatory Commission issued Order 888, which requires transmission-owning utilities to allow other power suppliers equal access to their transmission systems on non-discriminatory terms. As a result, many of the previously touted coordination benefits can now be achieved without a merger.

Today, mergers of both electric and gas utilities frequently produce comparatively small savings from reduced administrative costs and other economies of size (scale). Often merger savings are offset by the inefficiencies associated with the operation of a much larger organization. As a result, the customer may experience little or no reduction in the cost of electricity or natural gas and decreased customer choice and service.

Nevertheless, merger of energy utilities continues to proliferate. Appendix E shows the mergers that have been filed with the Federal Energy Regulatory Commission since 1997. This table includes the mergers affecting Indiana consumers: American Electric Power and Central and South West Corporation, SIGCORP and Indiana Energy, and NiSource and Columbia Energy Group. Not shown in the table is the recently announced merger between IPALCO and AES.

Electric and Gas Mergers in Indiana

In 1997 American Electric Power (AEP) and Central and South West Corporation (CSW) announced a merger and subsequently filed petitions with the necessary regulatory agencies, including the IURC. The IURC formed a negotiation team to insure Indiana retail customers were not harmed, either through the cross-subsidization of costs or by the degradation of service quality, by the merger. The negotiations resulted in a settlement agreement that provided for the pass-through of merger savings to Indiana retail customers and other provisions regarding the quality and reliability of electric service and the mitigation of possible market power of the merged company.

On June 14, 1999, Indiana Energy, Inc. and SIGCORP announced a merger. Shortly following this announcement, the Indiana Supreme Court issued a decision on the Ameritech – SBC merger. The Court held that the IURC did not have jurisdiction over transactions in the outstanding securities of a public utility or its parent. This decision significantly limited the IURC's ability to review and negotiate provisions of proposed mergers assure the fair treatment of Indiana retail customers.

Subsequently, when Indiana Energy and SIGCORP filed their merger petition with the IURC, the companies specified that the filing was "to the extent required" for merger approval. The companies offered no specific provisions to assure that some share of the benefits of the merger would flow back to Indiana retail customers. This case is still pending before the IURC although other regulatory agencies have given necessary approvals.

In the past year NiSource and Columbia Energy and IPALCO and AES have announced mergers. Nothing has been filed with the IURC regarding either of these mergers at this point in time.

<u>AEP – CSW Merger</u>

On December 22, 1997, AEP and CSW announced a stock-for-stock merger transaction creating a company with a total market capitalization of approximately $28.1 billion ($16.5 billion in equity $11.6 billion in debt and preferred stock). The new company would serve approximately 4.6 million customers and operate in Indiana, Ohio, Michigan, West Virginia, Virginia, Tennessee, Kentucky, Texas, Oklahoma, Louisiana and Arkansas.

On June 29, 1998, the IURC announced an investigation into the merger between AEP and CSW.[7] The IURC also intervened in the three FERC dockets initiated in connection with the proposed

[7] Cause No. 41210.

merger, advising that it had the jurisdiction to examine the effects of the proposed merger on service within Indiana.[8]

On April 26, 1999, the Commission approved a settlement agreement between AEP and a Commission negotiating team, In the Matter of the Investigation of the Commission's Own Motion Into Any and All Matters Relating to the Merger of American Electric Power, Inc., and Central and South West Corporation. The Order and settlement agreement detailed provisions for the distribution of both fuel and non-fuel merger savings to Indiana customers and specified actions the new company must take to prevent the development of market power. In return, the IURC agreed not to oppose the merger at the FERC.

The Citizens Action Coalition appealed the IURC's decision approving the settlement of the merger investigation. This appeal is still pending.

The FERC conditionally approved the merger on March 15, 2000. AEP and CSW made subsequent compliance filings to address the problems identified in the FERC's conditional approval order. On May 31, 2000, the FERC issued an order accepting the compliance filing. On June 15, 2000, the merger was completed.

Indiana Gas – SIGCORP Merger

On June 14, 1999, Indiana Energy, Inc. and SIGCORP, Inc. announced an agreement to combine into a new holding company called Vectren Corporation. The stock-for-stock transaction would create a combined company with a total enterprise value of approximately $1.9 billion based on the individual companies closing stock prices as of June 11, 1999.

The companies asserted that the merger would save $200 million over ten years by eliminating duplicate corporate and administrative functions and through greater efficiencies in operations. According to the companies, position reductions are expected to be 120 of the combined total of 1,850 jobs.

Through its subsidiaries, Indiana Gas and Southern Indiana Gas & Electric, Vectren would offer gas and/or electricity to more than 650,000 customers in adjoining service areas that covers nearly two-thirds of Indiana. Vectren's non-utility subsidiaries would offer energy-related products and services, fiber-optic based telecommunication services, materials management, locating and trenching services and energy marketing to customers throughout the surrounding region.

On June 17, 1999, Indiana Energy, Inc. and SIGCORP, Inc. filed a Joint Petition with the IURC for approval, to the extent required, of a proposed merger of equals. The companies on August 13, 1999, filed an application for merger approval with the Federal Energy Regulatory Commission.

[8] Docket Nos. ER98-2786-000, EC98-40-000 and ER98-2770-000.

The FERC approved the Indiana Energy/SIGCORP merger to form Vectren on December 20, 1999. The petition before the IURC is still pending with an evidentiary hearing scheduled for October 20 and 23, 2000.

NiSource – Columbia Energy Merger

NiSource, the parent company of Northern Indiana Public Service Company, announced its merger with Columbia Energy Group (Columbia), which is based in Herndon, Virginia on February 28, 2000. Columbia, one of nation's leading energy services companies, is involved in natural gas exploration, production, transmission, storage and distribution as well as propane and electric power generation, sales and trading. The company serves customers in thirty-four states and District of Columbia.

NiSource is a holding company whose primary business is the distribution of electricity, natural gas and water in the Midwest and Northeastern United States. The company also markets utility services and customer-focused resource solutions from Texas to Maine.

The combined company will serve more than four million customers primarily located in nine states. Its operations will span the high-growth energy corridor extending from the Gulf of Mexico to Chicago to New England, creating the largest natural gas distributor east of the Rockies, with wholesale and retail electric operations.

On July 17, 2000, Virginia approved the proposed merger, which completed the necessary state actions required for merger. Virginia's approval follows state actions in Pennsylvania, Maryland, Kentucky, Massachusetts, Ohio, Maine and New Hampshire. Shareholders of both companies approved the merger in June. The transaction cleared the waiting period under Hart-Scott-Rodino Antitrust Improvements Act at the U.S. Department of Justice and the Federal Trade Commission in July, and has received FERC approval. The transaction awaits SEC approval for completion. The merger is expected to be completed by the end of 2000.

IPALCO – AES Merger

On July 17, 2000, AES Corporation and IPALCO Enterprises announced an agreement whereby AES would acquire IPALCO Enterprises, Inc. for $25.00 per share in a stock-for-stock transaction. IPALCO Enterprises is a multi-state energy company providing a variety of energy products and services. Its regulated subsidiary, IPL, provides retail electric service to approximately 433,000 residential, commercial and industrial customers in Indianapolis, Indiana, and other central Indiana communities. IPL owns and operates 3,000 megawatts of coal-fired generation in Indiana.

AES is a global power company comprised of competitive generation, distribution and retail supply businesses in Argentina, Bangladesh, Brazil, Canada, China, Colombia, Dominican Republic, El Salvador, Georgia, Hungary, India, Kazakhstan, the Netherlands, Mexico, Pakistan, Panama, the United Kingdom, the United States and Venezuela.

The Company's generating assets include interests in one hundred forty one facilities totaling over 48,000 MW of capacity. AES' electricity distribution network delivers over 135,000 gigawatt hours per year to over 19 million end-use customers. In addition, through its various retail electricity supply businesses, the company sells electricity to over 154,000 end-use customers.

The proposed merger is subject to certain conditions, including receipt of the approval of IPALCO shareholders and receipt of regulatory approvals, including that of the Federal Energy Regulatory Commission and the Securities and Exchange Commission. AES and IPALCO have yet to make any of the necessary regulatory filings, but IPALCO shareholders are expected to vote on the merger in fourth quarter 2000. The parties anticipate receiving regulatory approvals and closing the transaction by early 2001.

The IURC's Authority Over Mergers and Acquisitions

The IURC's statutory authority over mergers and acquisitions evolved from a 1913 statute that has been amended over the years in response to changes in the regulated markets such as the abuses of holding companies during the Depression.[9] Federal statutory authority evolved, in part, from the Depression era abuses involving a handful of multi-state utility holding companies that controlled most of the nation's utilities. In response to these abuses, Congress enacted the Public Utility Holding Company Act (PUHCA) of 1935 to limit the power of holding companies. Since the depression, the energy industry has dramatically transformed from localized markets to regional (and to some extent, national) markets.

The IURC's authority over mergers was recently tested in the July 30, 1999, case involving the Ameritech – SBC Merger. In this case, the Indiana Supreme Court held: "[S]ection 83(a) does not confer Commission jurisdiction over transactions in the outstanding securities of a public utility or its parent." In response to the Supreme Court's decision, Ameritech withdrew its commitments to the consumers and the State of Indiana, which included six specific initiatives intended to foster local competition. Unless I.C. 8-1-2-83 is amended by the legislature, the IURC is clearly precluded from reviewing most, if not all, mergers and acquisitions. The Court specifically noted that if the Commission is to acquire jurisdiction over mergers, the jurisdiction must be specifically conferred by the legislature.[10] In writing for the Majority, Justice Boehm stated:

> The Commission and others make several compelling arguments, all of which boil down to the need for pre-merger investigation and approval by the Commission to protect the consumers of Indiana...It may well be that it is more efficient or effective in protecting the interests of the citizens of our state for the Commission to have power to disapprove a shift in control of a utility, rather than simply power to regulate the utility after its ownership is transferred.

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[9] I.C. 8-1-2-83. *(Formerly Acts: 1913,c. 76, s95; Acts 1925, c.54, s.1.) As amended by P.L. 59-1984, SEC.37; P.L.23-1988, SEC. 24: P.L.8-1993, SEC.111. and* I.C. 8-1-2-84: *(Formerly Act: 1913, c.76, s95.5; 1925, c.54, c.2., Acts 1939, c.19, s.3,; Acts 1973, P/L.61, SEC. 1,) As amended by P.L. 23-1988, SEC.25; P.L-1-1989, SEC. 15: P.L. 12-1992, SEC.57*

[10] Indiana Bell Telephone Co d/b/a Ameritech and SBC Communications, Inc. v. Indiana Utility Regulatory Commission, et al., 1999 Ind. LEXIS 548 (July 30, 1999).

In his Minority Opinion, Chief Justice Shepard observed that, as a state we have missed opportunities in banking, and possibly with our policies toward the insurance industry. The Chief Justice wrote:

> I find some modest solace in the acknowledgement of my colleagues that the policy arguments favoring supervision of business combinations...are compelling...[W]e cannot hope to thrive in the modern global economy unless our state acts with force and foresight at every opportunity.

The IURC's current authority is likely to be limited to trying to protect Indiana consumers from adverse effects from a merger rather than having any direct authority over the merger. Merger review and approval authority, including the ability to condition merger approval on requiring the merging companies to take specific steps to mitigate market power, is essential for the protection of customers from potential abuses of market power. It is also necessary for the Commission to have the requisite authority and staff to ensure compliance.

Federal Jurisdiction over Mergers and Acquisitions

While it is true that some mergers are reviewed at the federal level, no federal agency is charged with specifically protecting the interests of consumers in Indiana. The FERC's merger review, for example, has a national focus and does not generally concern itself with the potential ramifications on any particular state.[11] Consequently, the FERC is not likely to be overly concerned by the acquisition of an Indiana utility by an out-of-state entity or by an Indiana utility's acquisition of an out-of-state energy company. In some circumstances, the FERC's authority to review some types of mergers may also be at issue. In one recent case, for instance, the FERC Commissioners were divided on the FERC's jurisdiction to approve acquisitions of United States utilities by foreign entities.[12]

The Securities & Exchange Commission (SEC), Department of Justice (DOJ) and the Federal Trade Commission (FTC) also have limited merger approval authority. The SEC's review seems to be shadowed by an expectation that the Public Utility Holding Companies Act (PUHCA) will be repealed and the SEC's authority will soon be ceded to the FERC and/or to the states. The DOJ and FTC have thus far been much more involved in the review of telecommunications mergers than in the review of electric or gas utility mergers. The DOJ and the FTC, of course, also have to spread their limited resources to address all other types of industries in the United States economy and should not be counted on to devote resources to specifically safeguard the interests of Indiana.

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[11] The FERC's authority to approve mergers, or to condition its approval of a merger, is based on Section 201 and 203 of the Federal Power Act.

[12] EC99-49-000, New England Electric System and National Grid Group (United Kingdom) plc.

Merger Authority Available to Selected State Commissions

The following are brief excerpts directly from state statutes of merger authorities that are vested in a few selected state commissions:

California

(b) "Before authorizing the merger, acquisition, or control of any electric, gas, or telephone utility organized and doing business in this state, where any of the utilities that are parties to the proposed transaction has gross annual California revenues exceeding five hundred million dollars ($500,000,000), the commission shall find that the proposal does all of the following:

(1) Provides short-term and long-term economic benefits to ratepayers.

(2) Equitably allocates, where the commission has ratemaking authority, the total short-term and long-term forecasted economic benefits, as determined by the commission, of the proposed merger, acquisition or control between shareholders and ratepayers. Ratepayers shall receive not less than 50% of those benefits.

(3) Not adversely affect competition. In making this finding, the commission shall request an advisory opinion from the Attorney General regarding whether competition will be adversely affected and what mitigation measures could be adopted to avoid this result.

(c) Before authorizing the merger, acquisition, or control of any electric, gas, or telephone utility organized and doing business in the state...the commission shall consider each of the criteria listed in paragraphs (1) to (8) inclusive, and find, on balance, that the merger, acquisition or control proposal is in the public interest.

(1) Maintain or improve the financial condition of the resulting public utility doing business in the state.

(2) Maintain or improve the quality of service to public utility ratepayers in the state.

(3) Maintain or improve the quality of management of the resulting public utility doing business in the state.

(4) Be fair and reasonable to affected public utility employees, including both union and non-union employees.

(5) Be fair and reasonable to the majority of all affected public utility shareholders.

(6) Be beneficial on an overall basis to state and local economies, and to the communities in the area served by the resulting public utility.

(7) Preserve the jurisdiction of the commission and the capacity of the commission to effectively regulate and audit public utility corporations in the state.

(8) Provide mitigation measures to prevent significant adverse consequences which might result.

(d) When reviewing a merger, acquisition or control proposal, the commission shall consider reasonable options to the proposal recommended by other parties, including no new merger, acquisition, or control, to determine whether comparable short-term and long-term economic savings can be achieved through other means while avoiding possible adverse consequences of the proposal.

Illinois

(b) No reorganization shall take place without prior Commission approval. The Commission shall not approve any proposed reorganization if the Commission finds, after notice and hearing, that the reorganization will adversely affect the utility's ability to perform its duties under this Act. In reviewing any proposed reorganization, the Commission shall find that:

(1) the proposed reorganization will not diminish the utility's ability to provide adequate, reliable, efficient, safe, and least-cost public utility service;

(2) the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers;

(3) costs and facilities are fairly and reasonably allocated between utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility forratemaking purposes;

(4) the proposed reorganization will not significantly impair the utility's ability to raise necessary capital on reasonable terms or to maintain a reasonable capital structure;

(5) the utility will remain subject to all applicable laws, regulations, rules, decisions, and policies governing the regulation of Illinois public utilities;

(6) the proposed reorganization is not likely to have a significant adverse effect on competition in those markets over which the Commission has jurisdiction;

(7) the proposed reorganization is not likely to result in any adverse rate impacts on retail customers.

(c) The Commission shall not approve a reorganization without ruling on: (i) the allocation of any savings resulting from the proposed reorganization; (ii) whether the companies should be allowed to recover any costs incurred in accomplishing the proposed reorganization and, if so, the amount of costs eligible for recovery and how costs will be allocated.

Oklahoma

A. The Corporation Commission shall approve any merger or other acquisition of control referred to in Section 2 of this act unless, after a public hearing thereon, it finds that one or more of the following conditions will exist if such merger or other acquisition of control is consummated, in which event it shall disapprove such merger or acquisition of control and the same shall not be consummated.

(1) The acquisition of control would adversely affect the contractual obligations of the domestic public utility, or its ability or commitment to continue to render the same level of service to its customers that the domestic public utility is currently rendering;

(2) The effect of the merger or other acquisition or control would be substantially to lessen competition in the furnishing of public utility service in the state;

(3) The financial condition of any acquiring party is such as might jeopardize the financial stability of the domestic public utility or any party controlling such domestic public utility or otherwise prejudice the interest of the domestic public utility's customers;

(4) The plans or proposals which an acquiring party has to liquidate the public utility or any such controlling person, sell its assets, or a substantial part thereof, or consolidate or merge it with any person, or to make any other material change in its investment policy, business or corporate structure or management, would be detrimental to the customers of the domestic public utility and not in the public interest.

(5) The competence, experience and integrity of those persons who would control the operation of the domestic public utility are such that it would not be in the interest of its customers and the public to permit the merger or other acquisition of control.

Texas

(a) Unless a public utility reports the transaction to the Commission within a reasonable time, the public utility may not:

(1) sell, acquire, or lease a plant as an operating unit or system in this state for a total consideration of more than $100,000; or

(2) merge or consolidate with another public utility operating in this state.

(b) A public utility shall report to the commission within a reasonable time each transaction that involves the sale of at least 50% of the stock of the utility. On the filing of a report with the commission, the commission shall investigate the transaction, with or without a public hearing, to determine whether the action is consistent with the public interest. In reaching this determination, the commission shall consider:

(1) the reasonable value of property, facilities, or securities to be acquired, disposed of, merged, transferred, or consolidated;

(2) whether the transfer will

(A) adversely affect the health or safety of customers or employees;

(B) result in the transfer of jobs of citizens of this state to workers domiciled outside the state; or

(C) result in a decline of service;

(3) whether the public utility will receive consideration equal to the reasonable value of the assets when it sell, leases or transfers; and

(4) whether the transaction is consistent with public interest.

Minnesota

Subdivision 1. Commission approval required. No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for total consideration in excess of $100,000, or merge or consolidate with another public utility operating in this state, without first being authorized so to do by the commission. Upon the filing of an application for the approval and consent of the commission thereto the commission shall investigate, with or without public hearing, and in case of a public hearing, upon such notice as the commission may require, and if it shall find that the proposed action is consistent with the public interest it shall give its consent and approval by order in writing. In reaching its determination the commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of or merged and consolidated...

Enforcement Authorities Requested by the IURC

Based on the IURC's experience in the telecommunications industry, it seems certain that our inability to enforce our orders and rules will pose similar problems in the natural gas and electricity markets, as those markets become increasingly competitive. These concerns are not unique to Indiana. Other states, particularly those that have adopted retail competition legislation, have felt compelled to vest their state commission with substantial enforcement authorities. The telecommunications industry has demonstrated that effective competition depends on state commissions establishing "rules of the road" that include meaningful deterrents that can be imposed upon those who block or delay competition.

As some markets for electricity and gas become increasingly competitive while others remain regulated, there will be increasing tension for incumbent energy suppliers to gain competitive advantages by having captive customers in regulated markets subsidize operations in competitive markets. The FERC, for instance, adopted "Codes of Conduct" in an attempt to prevent some practices that would impede the development of a competitive wholesale market. In retail markets, some states have also adopted "Codes of Conduct" and "Affiliate Rules." The adoption of these rules is intended to prevent certain anti-competitive actions by regulated utilities vis-á-vis other market participants and with regard to their affiliates. Certainly, if the experience in telecommunications holds true for energy markets, we can expect the incumbent energy suppliers to erect barriers to keep out competition.

The Commission must have the tools to ensure that utilities provide adequate service for captive customers as the market transitions to greater competition. Preventing direct cross-subsidization of competitive markets by captive customers in regulated markets is just one example of the concerns that will have to be addressed by policymakers. Our experience in telecommunications (which, unfortunately, is commonplace in other state as well) demonstrates that firms minimize expenditures for captive customers and infrastructure. In some instances, reduced expenditures can be manifested in a deterioration of services such as connecting new customers or making repairs in a timely manner. In other instances, reduced expenditures can impede the introduction of new technologies or modernization of facilities. The decision to cut expenditures in the provision of reliable and high quality service might be done in order to improve the utility's financial position in other more competitive markets. As a consequence, there is a real concern that captive customers pay more for lower quality service.

In addition to a grant of legislative authority to establish a framework for effective competition, there will be a need for additional resources to monitor the markets, enforce Commission rules and regulations and remedy abusive behavior. Enforcement authority, without the requisite tools to adequately implement the public policy wishes of the State of Indiana, is tantamount to having no authority.

— State Competition Initiatives in Electricity —

Electric utility restructuring continues to be an active issue in many states. Regionally, Illinois began customer choice October 1, 1999, and the Ohio Public Utility Commission is in the process of reviewing and approving restructuring transition plans filed by the state's electric utilities. Michigan recently passed legislation that incorporates or supports many of the orders on restructuring issued by the Michigan Public Service Commission over the past few years. Kentucky continues to monitor the issue of restructuring but has not proposed or initiated any action to restructure its electric industry. The following discussion highlights the activities of these states. The discussion is a snapshot of recent activities but is not intended to detail all the events that have occurred over the last twelve months. A summary of restructuring activities for all 50 states can be found in Appendix C.

Illinois

In January 2000 the Illinois Commerce Commission (ICC) submitted a report to the Illinois General Assembly analyzing the development of competition in Illinois electric markets. Following is an excerpt from the Executive Summary of that report. The complete report is available on the Illinois Commerce Commission Website at: http://www.icc.state.il.us/icc/ec/docs.asp#genrep.

> On October 1, 1999, approximately 64,000 customers comprising an annual consumption of about 50 million mega-watt hours became eligible to choose new electric suppliers. About 57,000 commercial customers, 5,000 industrial customers and 2,000 governmental customers are eligible to choose an alternative provider. An additional 433,000 non-residential customers will become eligible by January 1, 2001.
>
> As of December 31, 1999, only ComEd [Commonwealth Edison] and Illinois Power customers have switched to alternative suppliers. The ComEd service territory is attractive to alternative suppliers, relative to other utilities' service areas, because of the large number of potential customers and the comparatively high rates for power in the ComEd region. It also appears that ComEd's federally regulated energy imbalance tariffs may better facilitate retail competition in Illinois than the tariffs of some other Illinois utilities. Finally, it appears that ComEd did not seek to retain customers through negotiated contracts for power and energy before open access, as did some others.
>
> In the first three months of open access, 4,682 ComEd customers, representing 25.8% of ComEd's eligible usage, switched from ComEd's bundled service to an alternative type of service. This represents approximately 6.7% of all eligible commercial customers and 15.8% of all eligible industrial customers.
>
> Of the 4,682 ComEd customers who switched service, 2,945 customers switched from ComEd's bundled service to service from a Retail Electric Supplier. The other 1,737 customers remained with ComEd but received service at lower rates by switching from bundled service to the Power Purchase Option (PPO), an alternative service available under the provisions set forth in Section 16-110 of the Public Utilities Act.
>
> The PPO allows customers subject to transition charges to purchase power and energy from the incumbent utility at a price determined by the Neutral Fact Finder (NFF). Alternative suppliers must offer service to potential customers at a price less than the PPO price to provide an attractive alternative to the local utility.
>
> Two non-residential customers in Illinois have chosen to take service under a utility's Section 16-107 Real-time Pricing tariff. Exceptionally high prices for power during the summer month in 1998 and 1999 highlighted for many potential users of the tariff the price risks associated with real-time pricing.

Retail Electric Supplier Activity: As of December 10, 1999, 13 suppliers are authorized to sell power and energy to Illinois retail customers. Currently, there are a few firms, which are the most active within the ComEd market. Among the more active suppliers are a Unicom affiliate and an affiliate of Central Illinois Light Company's parent AES. However, suppliers only began seeking certification from the Commission shortly before the market opened and therefore these results may be inconclusive.

Generally, suppliers have only shown interest in serving customers within the ComEd service area. The exception to this trend is Archer Daniels Midland Company, heretofore a customer of Illinois Power, which recently announced that it would switch its 300 MW load to AmerenCIPS beginning August 2000.

Information suggests that suppliers are marketing "PPO assignment" to customers as a significant part of their marketing efforts. Under PPO assignment, a customer sells to a supplier the customer's right to purchase power and energy from the host utility.

Potential Impediments to the Development of a Competitive Market: Before the market opened on October 1, 1999, some utilities signed a significant number of existing customers to new power and energy contracts. These customers tend to be the larger volume customers that are most likely to be at risk of leaving utility service in an open access environment. Customers who signed a power contract before the start of open access may be unable to switch suppliers during the early phases of electric restructuring.

Transition charges allow a utility to recover stranded costs, but transition charges also limit the amount of savings a customer can realize by switching electric suppliers. Because they limit savings, transition charges reduce the incentive for customers to switch suppliers and reduce the incentive for suppliers to actively pursue customers in Illinois.

The "reciprocity" provisions of the Act applicable to prospective alternative retail electric suppliers may have restricted the number of suppliers that can be authorized to serve Illinois retail customers.

Actual market prices for power and energy may be higher than the market prices estimated by the Neutral Fact Finder in the 1999 NFF report. If, in fact, the price for power determined by the NFF is too low, alternative suppliers are less able to compete on the basis of price.

Since the ICC report, there have been on-going efforts by customers and alternative suppliers to take advantage of the open access market. Recently, an alliance of cities, including Chicago, announced that they would pull the plug on Commonwealth Edison if one of the 13 alternative suppliers licensed in Illinois can offer them a better deal on electricity for municipal services over the next three years.

The government entities use about 400 MW per year, with the city of Chicago consuming about 200 MW and the Chicago Transit Authority using about 100 MW. This is the first opportunity these entities have had to purchase power competitively since Illinois deregulated electricity in 1997.

In order to qualify, an alternative retail service provider must lower costs for each member in the alliance by the same percentage amount and then guarantee these savings. The Request For Service sent to the 13 alternative providers was deliberately silent on any required savings figure in order to encourage competition among the bidders. Responses are due October 11. The alliance is hoping that negotiations can be completed in the fourth quarter, with service beginning January 1, 2002.

Kentucky

A special Kentucky Electricity Restructuring Task Force recommended that lawmakers wait until the 2002 General Assembly to consider opening the state's electric industry to competition. "There is no compelling reason at this time for Kentucky to move quickly to restructure," the 20-member task force concluded in its report.

The task force said in the report that Kentucky, which relies heavily on coal-fired generation, "is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains."

Despite the possibility of congressional legislation to mandate restructuring and actions taken by 23 states to restructure, there are "obvious advantages for Kentucky adopting a wait-and-see approach to electricity restructuring," the task force said. Such a position allows Kentucky to monitor the progress of restructuring in other states and to develop options that protect Kentucky's low rates for electricity, the task force added.

The task force also found:

- Restructuring can be expected to have multiple effects on Kentucky's electricity prices. If the state's electric rates are deregulated, price fluctuations probably would be larger in magnitude than fluctuations under cost-of-service regulation.
- Three utilities that operate in Kentucky – Cinergy, Big Rivers and the Tennessee Valley Authority – collectively have potential stranded costs that range from $295 million to more than $1 billion. The state's remaining utilities are in a "negative stranded cost" position, meaning the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market.
- Restructuring is not expected to reduce the importance of natural gas in new generating capacity in Kentucky. During the past 10 years, all new capacity in Kentucky has been gas-fired. The last coal-fired unit, Louisville Gas & Electric's 495 MW Trimble County plant came on-line during the early 1990s. "As the cost advantage for gas-fired generation continues to increase and the demand for electricity continues to grow during summer peaking months, the expectation is that new capacity will be gas-fired combustion turbines."

Michigan

After years of wrangling and numerous failed attempts, the Michigan Legislature finally passed an electric utility restructuring package which retains the numerous customer choice orders promulgated by the Michigan Public Service Commission over the past several years.

The legislation grants all customers the right to select their electric suppliers by January 1, 2002, and gives to residential customers a 5% rate cut for at least three years.

The legislative package (Senate Bill 937 with companion bills dealing with securitization and municipal utilities) was signed into law by Michigan Governor John Engler on June 3, 2000. The final version of the multi-bill package, deleted controversial language that prohibited non-utility affiliates who built merchant plants from selling the output directly to retail customers. Now, a merchant plant making sales to retail customers is considered an alternative electric supplier and must obtain a license under Michigan law.

The final version treats alternative suppliers as electric utilities in so far as they are required to secure franchise agreements in the municipalities and townships in which they plan to do business. In the final version, however, aggregators for schools are exempted from the franchise requirement, thus creating a breach between these aggregators and other power marketers.

The Senate passed a new stand-alone bill, SB 1256, on June 1, 2000, in an attempt to address this breach. It revises the law so that marketers who are not otherwise acting as electric utilities "tearing up roads to build new rights-of-way, for example" are not treated as utilities and do not, therefore, have to secure municipal franchises. This bill is currently before the House Energy and Technology Committee.

Ohio

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Am. Sub. S.B. 3 of the 123rd General Assembly). Governor Bob Taft signed the bill on July 6, 1999, and most provisions of S.B. 3 became effective on October 5, 1999, requiring each electric utility to file with the Public Utility Commission of Ohio (PUCO) a transition plan for the company's provision of retail electric service in Ohio.

On December 22, 1999, FirstEnergy Corp., on behalf of its Ohio operating companies (Ohio Edison, Cleveland Electric Illuminating Company, and Toledo Edison Company) filed the first transition plan with PUCO. Transition plans were later filed by American Electric Power, Cinergy and Dayton Power & Light.

On April 17, 2000, a stipulation was filed on behalf of FirstEnergy, the PUCO Staff, the Ohio Consumers' Counsel, Industrial Energy User-Ohio, Kroger Company, AK Steel, the Ohio Council of Retail Merchants, Shell Energy Services Company, Astabula County Community Action Agency, Corporation for Ohio Appalachian Development, Neighborhood Housing of Toledo, the Ohio Hospital

Association, the Cleveland Housing Network, and Consumers League of Ohio. The Ohio Manufacturers Association and the Greater Cleveland Growth Association also subsequently signed the stipulation. On May 9, a second agreement was filed at PUCO by FirstEnergy, NewEnergy Midwest, LLC, WPS Energy Services, Inc., and Columbia Energy Services Corporation, and Columbia Energy Powers Marketing. The Mid-Atlantic Power Supply Association, Strategic Energy, LLC, Exelon Energy, National Energy Marketers Association, Unicom Energy, Inc., and Enron Energy Services, Inc. signed the agreement as non-opposing stipulation parties.

Recently, the PUCO approved the stipulation in the FirstEnergy Corp. electric transition case which creates an opportunity to begin a competitive retail electric market in Ohio and provide opportunities for consumers to begin saving on their electric bills beginning January 1, 2001. Because this was the first transition plan to be approved, some of the major provisions of the plan are detailed below.

Under the terms of the stipulation approved by PUCO, FirstEnergy agrees to:

- Offer at least 20 percent (1,120 megawatts) of their tariff generation capacity to independent marketers, brokers and aggregators at fixed prices for resale to end users;
- Not increase distribution rates through December 31, 2007;
- Continue residential bill credits of $1.50 per month for Ohio Edison (OE), and $5 per month for Toledo Edison (TE) and Cleveland Electric Illuminating (CEI) residential customers;
- Create and maintain a technical task force designed to address and attempt to resolve technical and operational issues involving the companies that may arise following the beginning of customer choice;
- Continue to support low income housing energy efficiency improvements, with grants totaling $5 million per year through December 31, 2005. The available grants total $2 million per year each for OE and CEI, and $1 million per year for TE;
- Forego recovery of up to $500 million in transition costs if the 20 percent customer shopping rate is not met by the end of the market development period. Ohio law establishes a 20 percent benchmark for customer shopping rates; and
- Reimburse marketers for certain transmission costs.

American Electric Power, Cinergy and Dayton Power & Light have also filed stipulation agreements. The PUCO expects to rule on the individual agreements by late October 2000.

Wisconsin

Wisconsin Public Service Corp. (WPS) has announced it hopes to jump start the development of a competitive generation market in Wisconsin by transferring its wholly-owned generating units into a separate non-regulated generating company.

While there is currently no serious action toward restructuring Wisconsin's electric industry, WPS believes efforts should begin to move in that direction.

"In moving toward a competitive environment, other states have forced their utilities to sell off their generation component," said Larry Weyers, WPS chairman and CEO. "Those plants get bought up by the big national companies. If that happens here, I don't see how Wisconsin energy companies can survive as anything more than bit players in the new industry."

WPS has 1,200 MW of capacity principally made up of the six-unit, 360 MW Pulliam plant, the three-unit, 490 MW Weston Plant and five gas-fired peaking units representing 230 MW.

In its proposal, which WPS expects to file with the Wisconsin Public Service Commission in August, the utility states it will buy back the power under long-term contracts. It defers to the commission, however, to set the term of the power purchase agreements.

WPS said its proposal is only meaningful if existing utilities do not build new generation. New energy demands in Wisconsin would be met by the unregulated gencos and independent developers constructing new plants. "We must create a level playing field in which existing Wisconsin energy companies (not as regulated utilities) can compete with IPPs."

The move seems to be garnering support from both sides of the political spectrum. Democratic state Sen. Roger Breske, a senior member of the Senate Utilities Committee, called on the PSC to give it serious consideration. He also said he would push for a thorough review of the proposal by the Senate Utilities Committee. Assembly Speaker Scott Jensen, a Republican, said the proposal deserves consideration by lawmakers and the PSC.

With its proviso that regulated utilities refrain from building new generation in Wisconsin, the WPS idea stands in opposition to Alliant Energy's April 25, 2000, initiative to construct a 600 MW, rate-based plant in the state. That initiative has come under intense criticism by independent developers who charge that it subverts competitive bidding for incremental wholesale power facilities in Wisconsin.

— Review of the Natural Gas Industry —

Industry Structure

Gas utilities in the United States are categorized into municipally owned and investor-owned. Despite their different forms of ownership and corporate structures, municipal and investor-owned utilities share the goal of providing reliable gas service at reasonable cost. Because of the differences in governance and corporate structure, government policy does not affect each type of utility in the same manner.

Investor-Owned Utilities

Investor-owned utilities are the largest sellers of natural gas to retail customers in the United States. In Indiana, there are three large investor-owned gas utilities, Indiana Gas, NIPSCO and SIGECO, and 17 smaller IOUs. The three largest IOUs are owned by holding companies, with Vectren owning both Indiana Gas and SIGECO. Two of them, NIPSCO and SIGECO, also operate major electric utilities.

Gas IOUs, unlike their electric IOU counterparts, are not vertically integrated; they typically do not own gas production or pipeline facilities beyond their local distribution area.

Municipally Owned Utilities

There are 19 municipally owned gas utilities in Indiana. Indianapolis-based Citizens Gas and Coke, the largest municipal gas utility, and Aurora Municipal Utility are the only two municipal utilities currently regulated by the IURC. Municipals are organized as not-for-profit local government agencies and pay no taxes or dividends, although revenue can be turned over to the general city fund (in lieu of taxes) if the city elects to do so. Municipal utilities raise capital through the issuance of tax-free bonds.

Like their IOU counterparts, municipal gas utilities serve as a "reseller" and transporter to their retail customers. Typically, municipal gas utilities purchase gas supply and transportation rights rather than having any ownership in production or pipeline facilities.

Indiana Sales and Transportation of Gas

Local distribution companies (LDCs) serve as both merchants, providing bundled sales and transportation service to many of their customers, and transporters, moving gas through their systems for industrial and commercial customers that have purchased gas directly from producers or marketers.

Table 4 presents sales information for Indiana's four largest LDCs: Citizens Gas, Indiana Gas Company, NIPSCO and SIGECO. Sales figures are based on sales of gas made by LDCs to customers that purchase bundled service, which includes both the gas and transportation service. These four companies collectively represent about 90 percent of the natural gas retail deliveries in the state. For more detailed information, see Appendix B.

Table 4: Sales (Dth) for the Four Largest Gas Utilities in Indiana – 1999

Utility	Residential	Commercial	Industrial	Other	Total
Citizens Gas	23,070,234	11,904,795	2,754046	18,084	37,747,159
Indiana Gas	43,943,000	17,329,000	6,661,000	(950,000)	66,983,000
NIPSCO	65,168,000	21,061,000	11,090,000	34,468,000	131,468,000
SIGECO	8,566,559	3,663,170	467,093	(426,930)	12,269,892

Source: IURC data requests

U.S. Average Natural Gas Prices

Table 5 provides a comparison of average natural gas price by sector and state for 1999 and 2000. Along with several other states, information for Indiana was unavailable.

Table 5: Average Price* of Natural Gas by Sector and State -- 2000 and 1999

State	Citygate Price		Residential		Commercial		Industrial		Electric Utilities	
	2000	1999	2000	1999	2000	1999	2000	1999	2000	1999
Alabama	3.10	2.68	7.70	7.43	6.80	6.44	3.45	3.20	4.34	2.15
Alaska	1.60	1.33	3.60	3.55	2.14	2.39	1.41	1.18	1.63	1.69
Arizona	2.89	2.18	8.16	8.21	6.20	6.15	3.48	3.52	2.77	2.31
Arkansas	NA	2.87	NA	6.14	NA	4.90	4.51	3.43	2.87	1.97
California	2.78	2.19	6.77	6.55	6.58	5.75	4.22	NA	3.02	2.63
Colorado	NA	2.09	NA	4.72	NA	4.14	NA	2.30	2.69	2.83
Connecticut	5.66	4.57	10.51	9.97	6.97	6.85	5.46	4.38	NA	2.11
Delaware	3.40	3.54	7.67	8.07	6.13	6.66	4.00	4.06	4.44	3.18
Florida	3.51	3.22	10.91	10.63	6.99	6.35	4.31	3.79	3.17	2.86
Georgia	NA	3.72	NA	2.24	NA	2.86	NA	2.65	6.25	3.33
Hawaii	7.17	4.70	20.22	18.44	16.08	13.47	8.43	8.18	NA	NA
Idaho	2.54	1.82	5.53	5.08	4.88	4.51	3.49	3.19	NA	NA
Illinois	3.09	2.52	5.33	4.55	5.10	4.47	4.22	3.69	2.52	2.11
Indiana	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**3.31**	**2.94**
Iowa	3.34	2.79	5.66	5.00	4.82	4.17	4.08	3.38	2.91	3.50
Kansas	3.41	NA	6.10	NA	4.28	NA	3.70	NA	2.56	2.11
Kentucky	3.78	3.04	5.85	5.12	5.41	4.78	3.85	3.21	3.26	2.59
Louisiana	3.18	2.17	6.23	5.69	5.66	5.25	2.87	1.98	2.81	2.11
Maine	NA	3.06	NA	7.22	NA	6.68	NA	5.53	NA	NA
Maryland	3.80	NA	7.79	NA	6.82	NA	NA	5.38	3.80	3.51
Massachusetts	NA	NA	NA	NA	NA	NA	NA	NA	3.14	2.34
Michigan	3.01	2.86	4.82	4.74	4.66	4.67	3.96	3.78	1.85	1.73
Minnesota	NA	2.70	NA	5.02	NA	4.27	NA	2.78	3.11	3.18
Mississippi	3.27	NA	5.96	5.15	5.02	NA	3.47	NA	2.77	2.01
Missouri	3.31	2.67	6.16	5.63	5.77	5.37	4.88	NA	2.78	2.32
Montana	2.91	2.81	5.31	4.85	4.84	4.86	4.39	4.19	4.06	2.31
Nebraska	3.26	2.97	5.03	4.40	4.44	4.05	4.23	3.23	3.07	2.55
Nevada	NA	2.43	NA	6.78	5.40	5.88	4.85	4.49	2.86	2.29
New Hampshire	NA	3.53	8.31	7.73	NA	7.00	NA	6.56	3.18	NA
New Jersey	NA	NA	NA	NA	NA	NA	NA	NA	4.53	2.90
New Mexico	2.46	2.07	5.65	4.06	4.10	2.99	2.97	NA	2.54	1.96
New York	NA	NA	NA	NA	NA	NA	4.92	NA	4.09	2.67
North Carolina	3.78	2.95	8.18	7.33	6.82	6.18	4.98	3.68	4.26	3.34
North Dakota	NA	2.77	NA	4.67	NA	4.12	3.09	2.55	NA	NA
Ohio	5.26	4.39	6.18	5.74	5.89	5.45	5.27	5.17	3.80	3.59
Oklahoma	NA	3.05	5.81	4.97	5.67	4.86	4.54	3.48	3.22	2.49
Oregon	3.05	2.56	7.40	6.79	6.05	5.59	4.39	3.96	2.21	1.94
Pennsylvania	3.81	3.14	NA	7.77	6.03	7.17	4.96	4.49	3.28	2.95
Rhode Island	3.33	3.20	6.22	8.82	7.32	7.74	4.36	4.65	NA	NA
South Carolina	3.74	3.03	8.75	8.34	7.37	6.69	4.04	3.02	8.20	2.92
South Dakota	3.65	3.25	5.69	4.98	4.54	3.99	3.45	3.10	NA	NA
Tennessee	3.30	2.81	6.44	5.97	5.58	5.69	2.92	3.48	NA	NA
Texas	2.95	2.65	5.55	5.04	4.46	4.26	2.69	2.04	2.65	2.10
Utah	3.51	2.92	6.08	5.46	4.72	4.19	3.42	3.07	2.85	2.21
Vermont	3.58	2.92	7.39	6.54	6.18	5.26	4.20	2.80	3.29	2.52
Virginia	3.91	3.21	7.85	7.77	6.19	5.84	4.37	4.19	3.55	3.15
Washington	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
West Virginia	NA	NA	NA	NA	6.09	6.22	NA	NA	3.49	3.07
Wisconsin	3.15	2.60	6.17	6.01	5.16	4.92	4.27	3.82	3.17	2.72
Wyoming	4.17	3.14	4.99	5.05	4.20	4.52	NA	NA	2.75	5.64
Average	**3.43**	**2.82**	**6.49**	**6.07**	**5.34**	**5.08**	**3.35**	**2.98**	**2.83**	**2.29**

NA = Not Available --- * (Dollars per Thousand Cubic Feet, the information is preliminary based on year-to-date information) — **Note:** EIA has informed the IURC that three Indiana gas utilities have not provided the necessary data to enable the EIA to calculate the average price for Indiana.

Source: US Department of Energy, Energy Information Administration, Natural Gas Monthly, June 2000 tables 20-24.

Recent Increases in Indiana Gas Prices

Gas prices are projected to be higher for the upcoming heating season. According to American Gas Association (AGA), a number of factors are responsible for the increase in the cost of natural gas. Because the previous two winters were mild and gas consumption was low, reduced demand lowered prices. The average retail cost of gas fell 29 percent in 1998 from the previous year, which caused gas exploration and production companies to stop drilling for a nine-month period (August 1998 to April 1999). Prices for May 1999 rose, and new drilling and development resumed. By October 1999 there was a 60 percent increase in the number of rigs drilling from five months earlier, and the number of rigs has essentially remained at over 600. Gas well completions increased by 30 percent and have been greater than 1,000 per month since October 1999. Increases in drilling indicators point to an expectation that domestic production capability will remain strong in the foreseeable future and that price signals will encourage additional drilling.

Even with the increase in gas exploration and production, it still takes six to nine months before gas begins to move in interstate commerce, and eighteen months for offshore rigs. Because of the time lag between increased drilling, getting gas to market and a significant price response, it is unlikely that price reductions from increased drilling will be reflected on customer bills this winter.

Another factor contributing to the higher cost of natural gas are the increases in demand by all sectors. Ongoing economic growth continues to increase gas use by factories, other industrial customers and cogenerators, who consume about 40 percent of natural gas in the United States. High oil prices have prevented many factories and electricity generators from switching from natural gas to fuel oil. Gas-fired electricity generation is a small (about 15 percent) but fast growing component of gas demand. Data is not available to quantify the impact of the electric generation market on current natural gas demand.

A key variable affecting residential gas bills is the weather. The previous two winters were mild, and a return to normal weather would increase consumer heating bills even if gas prices were unchanged from last year's low levels. Significantly higher heating bills will result if projected increases in gas commodity prices are combined with higher gas consumption due to a return to normal, but colder, weather.

Despite increased gas prices for the upcoming winter, the supply of natural gas is expected to meet the demands of both firm and interruptible customers. Imports from Canada have doubled in the last decade, providing 13 percent of the gas consumed in the U.S., and are expected to continue to grow incrementally with demand growth.

Additional pipeline capacity moving Canadian imports to U.S. markets have added supply flexibility for U.S. consumers. It is expected that new gas supplies will begin flowing to Midwest markets through Alliance pipeline in mid-November 2000. The Alliance pipeline extends from British Columbia to Chicago and has an initial capacity of 1.325 Bcf/day.

Gas storage levels are significantly lower this year than at the same time last year but the comparison is misleading. Storage levels for June of 1999 were unusually high due to the warmer than normal winter of 1998-1999 and unusually low early summer natural gas prices that encouraged purchases for injection. In fact, supplies of natural gas held in underground storage are only somewhat below the five-year average for this time of year, and exceed the levels for both 1996 and 1997. Gas storage is expected to be 95 to 99 percent full by the onset of winter.

The impact of gas price increases will vary from utility to utility and depend on the composition of each company's gas supply portfolio. LDCs that are locked into long-term contracts at $2/Mcf for significant portions of their supply will have much lower gas costs than companies that do not have low-cost long-term contracts and who must rely on the spot market to procure gas, which has recently been around $5/Mcf.

Most Indiana LDCs use some form of gas cost averaging for billing customers. Although this does not prevent unexpected increases in the cost of gas, it can mitigate the effects of price spikes in gas prices for a day, a week or even months. Many LDCs offer customers a number of billing options that average and/or levelize customer bills over an extended period of time. Although these programs do not prevent gas cost increases, they do provide alternatives to consumers for managing their heating bills.

— Recent Developments in Natural Gas —

NIPSCO Alternative Regulatory Plan

To date, NIPSCO is the only natural gas utility in Indiana with a Commission approved alternative regulatory program to allow some of its customers to purchase their gas from a supplier other than the incumbent local distribution company. The Commission approved NIPSCO's "Choice" program in Cause No. 40342 on October 8, 1997, based on Indiana Code 8-1-2.5.

The first phase of this program (December 1997 through July 1998) was opened to customers in parts of St. Joseph County and included South Bend, Mishawaka, Granger and surrounding areas. Up to 50,000 residential customers and 1,500 commercial and industrial customers were eligible to select alternative natural gas suppliers. By April 1, 1998, 3,200 residential customers (6 percent) and 915 commercial and industrial customers (61 percent) participated in the pilot program. The pilot was expanded to 82,000 residential and 10,000 commercial and industrial customers for the August 1998 through March 1999 period. The pilot program was expanded to encompass NIPSCO's entire geographic service territory on April 1, 1999, but participation is limited to 150,000 residential customers and 20,000 commercial and industrial customers. Of NIPSCO's limited eligible customers, 6004 residential customers (4 percent) and 4,297 commercial and industrial customers (21 percent) were participating in the pilot program as of June 11, 1999. Participation in the pilot program as of July 27, 2000 included 12,704 residential customers (8 percent) and 3,759 commercial and industrial customers (19 percent).

The following gas marketers are participating qualified suppliers in the pilot program: Energy USA formerly NESI Integrated Energy Resources Inc. (a NIPSCO affiliate); NICOR Energy, LLC;

Volunteer Energy Corporation, and Columbia Energy Services Corporation.[13] Another supplier, WPS Energy Services, Inc., is qualified to provide service to pilot program participants but has not done so as yet. NIPSCO and its affiliate Energy USA serve 93 percent of all 150,000 limited eligible residential customers and the majority of commercial customers. NIPSCO continues to educate ratepayers on the availability, benefits and mechanics of the Choice pilot program. The Company also continues its market research efforts to evaluate its own performance in communicating information on the Choice program, and gauging customers' reactions.

The Office of Utility Consumer Counselor has been actively involved in the customer education and program evaluation and modification phases of the Choice program. The OUCC provided materials to help consumers compare various alternative supplier options and programs.

ProLiance

Citizens Gas and Indiana Gas formed ProLiance in 1996 for the purpose of assuming the gas supply portfolio for these two utilities. In this capacity, ProLiance administers the utilities' pipeline transportation contracts, storage contracts and procures natural gas supplies for the two utilities. On March 29, 1996, twenty industrial customers of the utilities petitioned the Commission to disapprove the contracts between Indiana Gas and Citizens Gas relating to ProLiance. The petitioners were later joined by the OUCC. The Citizens Action Coalition, NIPSCO, Louisville Gas & Electric, and Panhandle Eastern Pipeline Company intervened in the case.

The petitioners alleged that the contract between Indiana Gas and ProLiance should be disapproved as not in the public interest for the following reasons:

- the lack of competitive bidding and reasonableness of the contract terms;
- an alleged violation of the terms of a prior settlement agreement regarding the flow through of revenue to consumers derived from releasing unused pipeline capacity;
- the unapproved transfer of alleged utility assets and functions;
- the misallocation of the benefits of operational consolidation of the utilities;
- the circumvention of Commission regulation and oversight; and
- alleged anticompetitive effects on the marketplace.

Independent marketers claimed:

- the utilities should have had a competitive bid process to select an entity to provide the services;
- that because ProLiance is closely aligned with Citizens Gas and Indiana Gas, it already has a market presence among the longstanding customers of the two utilities which impedes fair competition.

[13] The merger between NiSource, the parent company of NIPSCO, and Columbia Energy Group, is expected to be completed by the end of 2000 (see page 22 for additional information). Upon final consumation of the merger, Columbia Energy Services will become an affiliate of NIPSCO.

In its order dated September 12, 1997, the IURC ruled that the agreements that created ProLiance are in the public interest, in part because of the efficiencies gained by consolidating the gas supplies of the two utilities.

The OUCC, CAC and the industrial customers appealed the decision. On September 25, 2000, Indiana's Supreme Court affirmed the Commission's ruling that the creation of ProLiance was in the public interest and that the Commission would continue to exercise regulatory authority and monitor the effects of ProLiance through gas cost adjustment and general rate proceedings. Further, the Court agreed that the Commission did not confine its examination of "public interest" to just customer interests, but also considered appropriate factors such as customer cost, Indiana Gas' previous settlements, the negotiations surrounding ProLiance's formation, anti-competitive price patterns, and effects on the gas transportation market.

Citizens Gas and Coke Alternative Regulatory Plan

Citizen's Gas and Coke Utility (Citizen's) filed a petition with the Commission on November 23, 1999, requesting authority to implement an alternative regulatory plan. Citizen's is the second major natural gas utility in Indiana requesting such authority. Currently, the utility is actively involved in settlement negotiations with the OUCC.

Citizen's provides natural gas services to 255,549 residential, commercial and industrial customers in and around Marion County, Indiana. The utility cites an increasingly competitive energy environment in which market forces replace traditional regulation as the primary reason for the proposed change. Implementation of its proposal will prospectively result in all customers being able to choose their gas supplier, with Citizens remaining one of the supplier choices. Key elements of Citizen's proposal include:

- Proposed tariff schedules detailing the new unbundled services to be phased-in over the six years subsequent to approval by the Commission.
- A new Gas Cost Adjustment mechanism filed with the Commission monthly and reviewed annually by the Commission for compliance with IC 8-1-2-42.
- Affiliate guidelines that serve as ethical codes of conduct between the utility distribution entity and both the utility supply entity and other third-party suppliers.
- Citizens will remain customers' default supplier and in specific circumstances will serve as the supplier of last resort.
- New service offerings for third-party suppliers providing gas supply services on Citizen's distribution system.
- No increase in its current rates, but modification to the currently used mechanism for the handling of profits made from its non-regulated ventures.
- Immediate service changes for large commercial and industrial users using over 50,000 therms annually in the first year. The second year will provide a hiatus when Citizens can refine and supplement processes implemented in the first year. Remaining commercial and industrial customers will be allowed to participate in the third year. Residential customers will be allowed to participate in years four through six in phases.

Once hearings are completed, the Commission will review the testimony and issue an order on this case.

FERC Order 637

FERC issued Order 637 on February 9, 2000, in response to its Notice of Proposed Rulemaking,[14] which sought comment on a variety of fundamental changes to current regulatory methods, and its Notice of Inquiry,[15] which questioned whether changes in cost-of-service rate methodologies should be implemented. The Order was the product of two years of internal debate, investigation, and public dialog by the FERC and other natural gas industry segments. Because the natural gas delivery network is increasingly competitive, the focus of the rule was to achieve incremental improvements in regulation and in the market as the commercial environment evolves.

The Order is designed to provide new economic opportunities and improve efficiencies within the gas transportation marketplace, while simultaneously protecting captive customers from the exercise of market power. Two recurring principals throughout the Order are that capacity should go to the shippers who value it the most, and that the Commission should continue to use essentially the same regulatory framework to avoid or correct market power problems. The rule revises aspects of the current regulatory model without making fundamental changes to it. The final rule:

- removes the price ceilings for short-term secondary market capacity release to enhance the efficiency of the market until September 30, 2002, when the Commission will review and possibly extend the program;
- permits pipelines to propose peak/off-peak rates to better accommodate rate regulation to seasonal demands of the market and to better allocate revenue responsibility between short-term and long-term markets;
- permits term differentiated rate structures to better allocate the underlying risk of contracting to both shippers and pipelines;
- revises requirements relating to scheduling procedures, capacity segmentation, and pipeline penalties to improve the competitiveness and efficiency of the interstate pipeline grid;
- narrows the right of first refusal to remove economic biases in the current rule and, at the same time, protects captive customers' ability to resubscribe to long-term capacity; and
- improves reporting requirements to provide more transparent pricing information and to provide more effective monitoring for the exercise of market power and undue discrimination.

On May 19, 2000, FERC issued Order 637-A, which responded to the requests for rehearing and clarification that accompanied the issuance of Order 637. For the most part, FERC reaffirmed Order 637. To the extent it granted clarifications or made changes, it focused on expanding the rights of shippers on pipelines and reduced the ability of pipelines' tariffs to define the service relationship with shippers.

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[14] Regulation of Short-Term Natural Gas Transportation Services, Notice of Proposed Rulemaking, Docket No. RM 98-10-000, 63 FR 42982 (Aug. 11, 1998), FERC Stats. & Regs. Proposed Regulations [1988-1998] 32,533 (July 29, 1998).

[15] Regulation of Interstate Natural Gas Transportation Services, Notice of Inquiry, Docket No. RM 98-12-000, 63 FR 42973, IV FERC Stats. & Regs. Notices 35,533 (July 29, 1998).

FERC has scheduled its first of several public staff conferences that will permit an industry-wide discussion of issues affecting natural gas transportation policies and the role such natural gas transportation services play in energy markets in general. On September 19, 2000, the first conference will focus on commodity markets and transportation policies and practices that will make these markets more liquid. The second conference will be held in January 2001 and will address affiliate issues. The third conference is scheduled for April 2001 and will focus on whether fundamental changes to the FERC's regulatory model are needed, such as use of performance based rates or two-track regulatory models with different approaches for captive and non-captive customers.

— State Competition Initiatives in Natural Gas —

The gas industry has been competitive for years at the wholesale and large end-user level, as customers routinely purchase their gas supplies and other load-managing services in the marketplace. The American Gas Association estimates that 90 percent of large-volume natural gas customers have the ability to select their own natural gas supplier, and that 40 percent of commercial customers either now can, or will soon be able, to choose their own gas supplier (see Appendix D). Increasingly, choice options are also becoming available to residential and small commercial customers.

Currently, twenty-three states and the District of Columbia have gas residential pilots that are either underway or proposed. California, Georgia, Iowa, Massachusetts, New York, New Jersey, Pennsylvania and West Virginia have initiatives that provide or will provide all customers with the ability to choose their own supplier. Similarly, utilities in Maryland, Michigan, Montana, New Mexico, Ohio and Oklahoma have proposed or implemented programs that provide all their customers with the ability to choose suppliers.

5. RELIABILITY CONCERNS

Electric-system reliability has become an increasingly hot topic over the last twelve months. Last summer's blackouts, capacity shortages and price volatility prompted federal, regional and state agencies to investigate the causes of the problems and identify and implement possible solutions. This section will first review the Commission's investigation and efforts to alleviate reliability concerns and then will provide an overview of other groups' investigations.

— IURC Investigation and Review of Electric-System Reliability —

During the period, July 22 – August 2, 1999, throughout the Midwest, utilities' generation capacity was stretched to its limits due to successive days of temperatures in the mid-and upper-90° F and heat indexes over 100° F. Many utilities in the region, including all of Indiana's electricity-supplying utilities, requested voluntary conservation by customers to help reduce the possibility of rolling blackouts.[16] Following this event, the Commission staff began an informal process to meet with each of Indiana's electric utilities to discuss their experiences during the heat wave.

The Commission staff produced a report detailing the utilities' experiences during the heat wave.[17] A summary of the major findings follows:

- Weather conditions played a significant role in the capacity shortage during the period. Not only were high temperatures driving up electricity usage by customers for air conditioning needs, low river water levels and high water temperatures decreased the amount of electricity some generating units could produce.
- Electric generation capacity has decreased to critical levels relative to demand. Most electric utilities agreed that new generation capacity is needed in the region.
- Utility tariffs designed to encourage customers to reduce their electricity usage under certain conditions were helpful in reducing demand during the heat wave. The utilities were planning on expanding these types of tariffs in the future.
- The wholesale markets and transmission access are not as competitive and efficient as they should be. The fact that most transmission providers are also wholesale power suppliers raises concerns that transmission access is being manipulated to the benefit of the affiliate wholesale power supplier.
- Most utilities initiated at least some portion of their emergency operating plan during the heat wave and found this helpful in dealing with the critical situation.

Throughout the fall and winter of 1999/2000 the IURC monitored and reviewed reports by other groups and agencies on the 1999 heat wave. The observations and conclusions were similar to what the IURC found during its meetings with Indiana utilities.

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[16] A rolling blackout is a situation where the utility cuts off electricity to geographical segment of its customers in order to maintain the stability of the electric system, as a whole. The outages are rotated through segments of the utility's system for specific periods (typically 1-2 hours) of time so that no single group of customers is inconvenienced by the outages.

[17] This report can be found on the IURC website at www.ai.org/iurc/energy/papers.html.

In the spring 2000, the IURC issued a survey to determine how the utilities were preparing for the summer peaking season. The utilities generally reported that they 1) were planning to complete all maintenance activities by June; 2) had arranged various purchase power contracts or purchase options; 3) were in the process of, or had implemented new tariffs and programs to encourage customers to reduce electric usage during peak periods; and 4) had reviewed and revised, where necessary, their emergency operating plans to help address any critical situation that may arise during the summer 2000. These surveys were followed-up by a public meeting that allowed the utilities to describe the preparations for summer 2000 directly to the commissioners and staff.

As a result of the information learned through IURC efforts plus other factors, such as recent actions by the Environmental Protection Agency and federal courts and the construction of non-utility owned generation facilities, the Commission initiated an investigation into all matters affecting the adequacy and reliability of electric service to Indiana retail customers.[18] The initiating order stated:

> One goal of this proceeding is to better inform the Commission of the complex issues associated with maintaining reliable electric service, but another is to increase the public awareness of these complexities. The ultimate objective of this proceeding is to develop policies and initiatives to promote and maintain adequate and reliable electric service. It is our hope that this proceeding will allow the parties to have interactive discussion that will be one of the tools this Commission may use in the future as it evaluates the energy needs of our State.

As part of the proceeding, the Commission staff prepared a schedule of seven workshop topics and a list of questions for each workshop. Interested parties were asked to provide written responses to the questions prior to the actual workshop. The responses would be used to formulate an agenda and follow-up questions for the corresponding workshop.[19] Following is a brief description of each of the workshops:

- **Session 1: Alternatives to Traditional Generation Resources**
  Objective: The objective of this session is to examine alternatives to building new generation facilities to maintain or enhance system reliability. Alternatives to be discussed will include technologies such as distributed generation, "green power" resources and customer load management strategies such as conservation programs and curtailable or interruptible options.

- **Session 2: Recent Environmental Protection Agency (EPA) Actions**
  Objective: This session will examine the plan and strategies for maintaining system reliability assuming the utilities will be required to meet new EPA standards. The Commission is particularly interested in how the utilities may be coordinating among themselves to assure reliability. Also, the Commission is interested in learning if and how non-utility owned generation might be used to help maintain reliability.

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[18] Cause No. 41736, issued May 10, 2000.

[19] The questions for each workshop topic can be found on the IURC website at www.ai.org/iurc/energy/indexrelpro.html.

- **Session 3: Multi-State Utility Operations**
  Objective: The objective of this session is to examine how retail restructuring in other states and the competitive wholesale market affect reliability in Indiana. The Commission would like to discuss strategies or methods for maintaining electric reliability for the native load customer.

- **Session 4: Regional Reliability Issues**
  Objective: The objective of this session is to discuss how the reliability of the electric system in Indiana may be maintained or improved by regional entities such as Regional Transmission Organizations or Power Exchanges. The increasingly regional operation of wholesale markets and the need for access to region-wide transmission facilities makes it necessary to find ways to address reliability from a regional perspective. The Commission is interested in discussing methods of encouraging regional solutions to reliability concerns.

- **Session 5: Generation Planning and Reserves**
  Objective: The objective of this session is to review the technical planning process used by the utilities and to examine the strategies used to maintain reliability standards based on the results of the planning process. Particular attention will be given to how the rapidly changing electric utility industry makes the planning process more difficult and how these factors are incorporated into utility strategies for meeting customer demand and maintaining system reliability.

- **Session 6: Non-Utility Owned Generation**
  Objective: The objective of this session is to examine the effects of non-utility owned generation on statewide and regional reliability. The Commission would like to discuss the advantages and disadvantages of having non-utility owned generation built in Indiana. Also, the factors that influence the construction of non-utility owned generation (access to natural gas, access to transmission lines and the robustness of the wholesale market) will be reviewed. Finally, the Commission would like to address how non-utility owned generation should be viewed when assessing the generation capacity status of the state and region.

- **Session 7: Quality Service Issues**
  Objective: The objective of this session is to examine how reliable electric service is to the end-use customer. This session will discuss the very basic concepts of reliability; how often electric service is interrupted; how long the interruptions last and how responsive the utility is to customer questions and problems. Further, this session will address the development of appropriate service quality standards and what will be required to implement and monitor service quality standards. Finally, this session will address if different customers have different service quality needs and how the utility may be able to use that difference to maintain or enhance reliability for all its customers.

To date, sessions one through four have been completed. The Commission anticipates completing the workshops by the end of the year.

— Reviews of Electric-System Reliability by Other Organizations —

Since the summer of 1999 electric-system reliability has received a great deal of attention from federal, regional and state agencies and groups. This section will highlight some of the major investigations and reports.

East Central Area Reliability Council (ECAR)

Following the July 1999 heat wave, ECAR and its national counter-part, the North American Electric Reliability Council (NERC), recognized there had been significant balancing problems during that period.[20] ECAR surveyed all members for the 10 hours it believed to be the most out of balance. ECAR subsequently focused its review on the three companies, AEP, Hoosier Energy and Cinergy, that had the most hours in violation and the greatest discrepancy from their set balancing standard. ECAR eventually cleared Hoosier and AEP of the violations but determined that Cinergy had *leaned* on the system in eight of ten hours, siphoning as much as 1,664 MW in one hour. Cinergy's balancing standard is 165 MW.

Letters of reprimand were sent to all the CEOs of companies that violated their balancing standards but neither ECAR nor NERC had any more severe sanctions in place to address this type of behavior. On April 18, 2000, East Central Area Reliability Council, on behalf of its 16 Control Area members, submitted to FERC for filing an Inadvertent Settlement Tariff that is intended to obligate each party to make payment and to entitle each party to receive compensation for Inadvertent Interchange from each other party pursuant to ECAR's Inadvertent Settlement Procedure.[21] On May 31, 2000, the FERC accepted ECAR's Inadvertent Settlement Tariff.

Finally, ECAR produces a semi-annual report assessing the load and generation capacity for the next peaking season, either summer or winter. In May 2000, ECAR issued its assessment for summer 2000.[22] In the report, ECAR concluded that the capacity margin[23] in the region was expected to be 11.2% during the peak demand as compared to 10.8% for the summer of 1999. ECAR expects a net import of power at peak exceeding 2,900 MW. ECAR noted that severe weather (abnormally hot and humid) or unexpectedly low generator availability could make it necessary to curtail customer load beyond contractually interruptible loads and demand side management.

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[20] Balancing refers to making the power coming into the region equal with the power being drawn from the electric system by a utility for its end-use customers. ECAR has set standards designed to keep the electric system in balance. It uses a formula to establish a maximum imbalance per hour for each control area. The imbalance number is roughly related to the size of the utility.

[21] Imbalances in the power system are sometimes referred to as inadvertent flows or interchange.

[22] 2000 Summer Assessment of Load and Capacity, 00-GRP-33, East Central Area Reliability Coordination Agreement, May 2000.

[23] Capacity margin equals ((utility generation capacity minus peak demand) divided by generation capacity) times 100.

U.S. Department of Energy's Power Outage Study Team

In response to public concerns about power outages and other electric system disturbances, particularly evident during the summer of 1999 heat wave, the Secretary of Energy brought together a team of experts to study some of those events. This team, the Power Outage Study Team, or POST, consisted of experts from the Department of Energy, the national laboratories and the academic community. The team examined a number of critical events in detail and produced a report recommending actions to avoid future outages. The report was distinctive from previous similar reports in that it took into consideration the extensive restructuring happening in the electric industry.

In its study, POST examined eight electric reliability problems, six power outages and two power system disturbances which all occurred between early June and early August 1999. The team interviewed the affected utilities and system operators, as well as other local parties and reviewed available reports and materials that had been prepared following the events. The events that were studied are shown in Table 6.

Table 6: Summer 1999: Electric Power Events Studies by POST[24]

Event/Location	Date
Outages: New York City	July 6 and 7
Long Island	July 3-8
New Jersey	July 5-8
Delmarva Peninsula	July 6
South-Central states	July 23
Chicago	July 30-August 12
Power System Disturbances: New England states	June 7 and 8
Mid-Atlantic area	July 6 and 19

Following is a brief summary of the recommendations made by POST to the Secretary of Energy in the report:

- Promote market-based approaches to ensure reliable electric service. Mechanisms that will ensure adequate supplies of electricity and reliable operations should be designed with the principle that competition and markets make better investment decisions than regulators. But, because electric service is provided through a network, it has aspects of public good and may be under-provided by private entities.
- Enable customer participation in competitive markets. The ability of customers to manage their demand in response to market prices is the key to ensuring both reliable electric service and an efficiently functioning competitive electricity market.
- Remove barriers to distributed energy resources. Distributed generation technologies may help utilities to respond more rapidly to an increased demand for electricity in areas where demand is already high and may improve the quality of power to the customer.

[24] Report of the U.S. Department of Energy's Power Outage Study Team, Findings and Recommendations to Enhance Reliability from the Summer of 1999, Final Report, March 2000, p. 3.

- Support mandatory reliability standards for bulk-power systems. The interconnected electric power system was primarily designed by individually integrated utilities to deliver power to their end-use customers. Recent changes in the electric power system to allow for a competitive wholesale generation market have made voluntary reliability standards inadequate. Mandatory standards are necessary to ensure that the "rules of the road" are being implemented in a fair, non-discriminatory manner.
- Support reporting and sharing of information on "best practices." Current forums for sharing information raise concerns about the consistency of some information, the availability of information to all industry stakeholders and the continued viability of these forums.
- Enhance emergency preparedness activities for low-probability, high-consequence events on bulk-power systems.
- Demonstrate federal leadership through promoting best reliability practices at federal utilities.
- Conduct public-interest reliability-related research and development consistent with the needs of a restructuring electric industry.
- Facilitate and empower regional solutions to the siting of generation and transmission facilities. Stable incentives for investing in generation and transmission must be complemented by siting boards that can discharge their responsibilities in a timely and coordinated fashion.
- Promote public awareness of electric reliability issues. Greater understanding of electric reliability issues, including frequency and causes of outages and the steps being taken to prevent and limit the consequences of outages, will lead to better-informed decisions by consumers.
- Monitor and assess vulnerabilities to electric power system reliability.
- Encourage energy efficiency as a means for enhancing reliability.

Other

The Indiana Utility Regulatory Commission has not been the only commission in the region to review the reliability of its electric utilities. In April, 2000 the Public Utilities Commission of Ohio opened an investigation and ordered Ohio investor-owned electric utilities to respond to its inquiries concerning the companies' readiness to respond to anticipated higher demands for electricity in summer 2000. The Illinois Commerce Commission on May 19, 2000, held a meeting with representatives of Commonwealth Edison Company, the Mid-American Interconnected Network (MAIN) and the North American Electric Reliability Council (NERC) to discuss electricity and reliability issues for the summer. Finally, on June 9, 2000, the Michigan Public Service Commission released its Michigan Energy Appraisal: Summer 2000 report. This is a semi-annual report with a much broader scope than just electric reliability but it still presented some of the potential risks to electric reliability.

Finally, electric system reliability has been a critical issue in the debate of electric industry restructuring currently on-going in the U.S. Congress. The lack of consensus on a comprehensive electric industry restructuring bill had lead some lawmakers to propose a stand-alone bill on reliability. The issue continues to be hotly debated. See Section 8 for a more detailed discussion on federal legislative activity regarding restructuring the electric industry.

6. MERCHANT POWER PLANTS

Merchant power plants are considered different from traditional utilities in that the electricity they generate is sold in the wholesale market, not to retail customers. Because they operate in the wholesale market, the company which constructs the merchant plant will generally assume the full risk of the construction and operating costs which traditionally regulated utilities recover from their customers through the rate-making process. To be as competitive as possible, merchant plants have been choosing their site location in order to be as close as possible to both a gas pipeline and an electricity transmission line. Keeping the cost of transportation low helps the plants to be more competitive in the wholesale market.

Merchant plant electricity is typically generated by either a single or combined cycle combustion turbine that is fueled by natural gas. A single cycle combustion turbine simply uses the gas to power its turbine (like a jet engine) and produce electricity. In the case of a combined cycle turbine, the heat from the turbine is captured and used to create additional electricity. The vast majority of the proposed merchant plants in Indiana plan to be either gas-powered single or combined cycle combustion turbines. A coal-burning cogeneration plant had been proposed by Southern Indiana Gas & Electric but the details of the project were never finalized. SIGECO eventually requested that the petition for the cogeneration project be dismissed.

For the past ten years, Indiana's electric companies have been opting not to invest in new generating plants and/or increasing their output due to concern over changes in the industry and the fear of stranded costs. Therefore, over the past ten years Indiana capacity margins have fallen from over 30% in 1987 to less than 10%, based on 1998 data.[25] Instead of investing, many utilities have been purchasing their additional power on the open wholesale markets from merchant plants. While this can be cost-effective in the short-term, it can expose both the utility and its customers to the volatility of the wholesale market. Although the merchant plants locating in Indiana are not necessarily going to sell their power to companies in Indiana, many observers maintain that they will help improve capacity margins and reliability regionally.

Up to this point, all the merchant plant petitioners have been designated as public utilities under I.C. 8-1-2-1. However, the IURC considered that the petitioners are not exercising any of the rights, powers, or privileges of public utilities and are not planning to sell electricity to retail customers or recover any of their costs through a rate base. Based on these considerations and the need for increasing our state's generating capacity, the Commission has been declining jurisdiction over the petitioners and the construction and operation of their proposed merchant plants. Thus far, proposed merchant plants in Indiana and in other states have been designated as exempt wholesale generators (EWG), as defined by the Public Utility Regulatory Policies Act (PURPA), and are subject primarily to federal regulations.

[25] Indiana capacity margins calculated based on peak demand and generation capacity information from the 1998 and 1999 Indiana Electricity Projections by the State Utility Forecasting Group.

Two Indiana investor-owned utilities, IPL and SIGECO, have built or are planning to build peaking power generation units which are similar in structure to typical merchant plants. The difference between the two is that while merchant plants sell their electricity on the wholesale market, peaking plants are used by a utility for additional generation during periods of increased demand. Therefore, although these plants are not merchant plants, since they serve retail customers (but are not included in the approved customer rates of the companies), for completeness, we have included the plants in this section.

Table 7 compares the proposed (not approved) merchant plant capacity across the country. Indiana and its surrounding states are in bold face print. Table 8 details the merchant plant petitions either currently before the commission or in the process of being constructed.

Table 7: Proposed Merchant Plant Capacity by State Ranked by Total Capacity

Rank	State	Plant Capacity (MW)
1	Texas	26197
2	California	13460
3	**Illinois**	**11419**
4	Massachusetts	11047
5	Florida	9797
6	New York	8585
7	Arizona	8100
8	Pennsylvania	7070
9	**Ohio**	**6742**
10	Mississippi	6705
11	**Michigan**	**5230**
12	**Indiana**	**5217**
13	Connecticut	4586
14	Arkansas	4293
15	Louisiana	3920
16	Georgia	3786
17	Oklahoma	3610
18	Alaska	3331
19	New Jersey	3200
20	West Virginia	2616
21	Maine	2603
22	Missouri	2490

Rank	State	Plant Capacity (MW)
23	Montana	2160
24	Maryland	2085
25	Wisconsin	2041
26	**Kentucky**	**1990**
27	Nevada	1536
28	New Hampshire	1430
29	Vermont	1225
30	Iowa	1200
31	New Mexico	1174
32	Washington	1156
33	Tennessee	1110
34	North Carolina	980
35	Rhode Island	832
36	Oregon	780
37	Virginia	733
38	Delaware	588
39	Colorado	560
40	Minnesota	550
41	South Carolina	453
42	Wyoming	440
43	Idaho	250

Source: Electric Power Supply Association (6/7/00)

Table 8: Merchant Plant Filings before the Commission

Proposed Facility	Proposed Capacity	Location	Estimated Completion Date	Cause Number
DPL Energy	400 MW	Wells Co.	Spring 2001	41685
Whiting Clean	525 MW	Whiting, IN	June 1, 2001	41530
SIGECO	80 MW	Posey Co.	Summer 2001	41749
Cogentrix	Up to 800 MW	Bedford, IN	Summer 2002	41566
PSEG Lawrenceburg	1150 MW	Dearborn	Summer 2002	41757
Sugar Creek Energy	533 MW	Vigo Co.	June 1, 2002	41753
Duke Energy Knox	640 MW	Knox Co.	June 1,2002	41803
Duke Energy Vigo	620 MW	Vigo Co.	June 2002	41804
State Line II	550 MW	Hammond,	January 1, 2003	41590
Tenaska	1800 MW	Pike Co.	Second Quarter 2003	41823
Cincap VII	132 MW	Cadiz, IN	Delayed	41569

Exhibit 1: Merchant Power Plants Currently in Operation in Indiana

West Fork, Knox County

Owned by Enron
Capacity: 500 MW

The West Fork Plant has four simple cycle combustion turbines that are powered by natural gas. All output from the facility will be delivered to transmission lines owned and operated by either Cinergy or IPL for transmission and sale on the wholesale market. The IURC approved their petition on 8/25/99 and the facility was operating in June 2000. (Cause number 41411.)

DTE Georgetown, Indianapolis

Owned by DTE Energy
Capacity: 160 MW

DTE Georgetown has two combustion turbines that are powered by natural gas. All output from the facility will be delivered to transmission lines owned and operated by IPL for transmission and sale on the wholesale market. The IURC approved their petition on 12/15/99 and the facility was operating June 2000. (Cause number 41566.)

IPL Georgetown, Indianapolis

Owned by IPL
Capacity: 80 MW

IPL Georgetown has one combustion turbine that is powered by natural gas. All output from the facility will be delivered to transmission lines owned and operated by IPL for transmission and sale on the wholesale market. The IURC approved their petition on 4/7/99 and the facility was operating in May 2000. (Cause number 41337.)

Duke Energy Vermillion, Vermillion County

Owned by Duke Energy
Capacity: 640 MW

The Duke Energy Vermillion Plant has eight combustion turbines that are powered by natural gas. All output from the facility will be delivered to transmission lines owned and operated by PSI for transmission and sale on the wholesale market. The IURC approved their petition on 4/7/99 and the facility was operating in June 2000. (Cause number 41388.)

Worthington Generation, Greene County

Owned by Worthington Generation
Capacity: 170 MW

Worthington Generation purchased this plant from AES Corp. It has four combustion turbines and is powered by natural gas. All output from the facility will be delivered to transmission lines owned and operated by Hoosier Energy for transmission and sale on the wholesale market. The IURC approved their petition on 3/11/99 and the facility was operating in June 2000. (Cause number 41361.)

Total Capacity: 1550 MW

7. EPA ACTIONS

On October 27, 1998, the U.S. Environmental Protection Agency (EPA) published a final federal rule (commonly called the NOX SIP Call; SIP is an acronym for State Implementation Plan) that requires each of the twenty-two states in the eastern United States, including Indiana, to reduce emissions of nitrogen oxides significantly (an approximate 85% reduction from 1990 levels). The compliance deadline is May 2003. Nitrogen oxides (NOX) are a precursor to ozone formation, and the federal rule is intended to reduce the transport of ozone and ozone pollutants that occurs in this multi-state region. The NOX SIP Call affects several types of large industrial boilers, but the bulk of reductions fall primarily on the electric utility industry.

Numerous parties (many of the 22 states and groups of utilities) challenged EPA's rule in the District of Columbia U.S. Court of Appeals. In March 2000, the Court upheld the NOX SIP Call Rule. A subsequent request for rehearing was denied. EPA has directed each state to file their final SIP to comply with this rule by October 28, 2000. If a state does not file a final plan by the deadline, the EPA can implement the rule for that state. The Indiana Department of Environmental Management (IDEM) has begun their rulemaking process, but due to statutory requirements, it takes about one year to finalize the rule. IDEM has conferred with EPA on this matter, and several other states have similar processes, so it is unlikely that EPA will take over the implementation of the rule itself if Indiana has not submitted its final plan by the deadline. IDEM expects that its NOX SIP Call rule will be finalized around June 2001.

Another regulation affecting allowable NOX levels originated in the Clean Air Act. It set a one-hour ozone standard that local areas must meet or attain. This regulation has resulted in a separate and overlapping IDEM rulemaking regarding NOX (the state NOX rule). Indiana has four counties that are considered non-attainment areas: Lake, Porter, Clark and Floyd. Under EPA regulations, Indiana faced a deadline to submit a plan by the end of 2000 that brings these areas into attainment. Although the NOX SIP Call reductions are expected to accomplish this, the outcome of that rule was unclear during the litigation period. Therefore, in order to complete a rulemaking by the end of 2000, IDEM was forced to begin a rulemaking for the non-attainment areas late last year. This state NOX rule requires an approximately 65 percent reduction of NOX from electric utilities starting in May 2003. IDEM expects final adoption of this state NOX rule in December 2000. The NOX SIP Call rule (85 percent reduction) will supercede this state NOX rule once it becomes final next year.

IDEM estimates capital costs for the state NOX rule (65% reduction) for electric utilities at $716 million to $1,180 million and annual operating and maintenance costs during the ozone season are estimated at $134 million to $207 million.[26] Costs for the NOX SIP Call rule will be higher, but have not yet been estimated by IDEM.

Since the pollution control equipment to control NOX must be installed and operating by May 2003, utilities now have five outage windows, beginning with spring 2001, in which to get the work done.

[26] Administrative Rule Fiscal Impact Statement, Proposed Rule 98-235, Department of Environmental Management, July 26, 2000.

An outage window occurs in the spring and fall of each year when demand for electricity is lower. Utilities perform various maintenance activities during these windows. The NOX pollution control equipment installations will require generating units to be offline for a longer time period. This additional outage time creates a risk to the reliability of power; specifically to generation adequacy, which means simply having enough power to meet consumer needs. One mitigating factor to this reliability risk is the addition of new merchant plant generation across the region.

Two other areas of EPA actions are worth noting. Under Section 126 of the Clean Air Act, the EPA granted petitions filed by states claiming that other states' pollution has contributed to their local ozone problem. The petitions granted apply to facilities in the eastern half of Indiana owned and operated by AEP, PSI Energy, IMPA, the City of Richmond, and the Indiana-Kentucky Electric Corp. Petitions applying to facilities in the western half of the state are pending. The pollution targeted is again NOX emissions, but the remedy appears to be no harsher that the limits in the NOX SIP Call, and so these petitions are somewhat superfluous at this point.

The EPA, through the Department of Justice, has filed a lawsuit against seven utilities (including AEP, Cinergy, and SIGECO) claiming that they "violated the Clean Air Act by making major modifications to many of their plants without installing the equipment required to control smog, acid rain and soot." Utilities consider the activities to be routine maintenance and repair, and are fighting the lawsuit in court. Possible remedies include fines and the installation of the most up-to-date pollution control equipment.

8. FEDERAL LEGISLATIVE UPDATE

This year, one restructuring bill went farther than the other 20+ that were introduced; H.R. 2944, a bill introduced by Rep. Joe Barton (R-TX), Chairman of the Subcommittee on Energy and Power. H.R. 2944, known as the Electricity Competition and Reliability Act, was reported out of the House Commerce Subcommittee on Energy and Power in October 1999, which is more progress than any other restructuring legislation has seen. The bill promotes competition by clarifying states' authority to require electric utilities to provide unbundled local distribution service to consumers in the state, but does not require competition by any certain date. The legislation also states that nothing in the federal legislation will preempt or override the terms of any state retail access plan ordered prior to or within three years of enactment.

Several provisions of the legislation deal with the authority of the Federal Energy Regulatory Commission (FERC). H.R. 2944 provides for the FERC certification of a self-regulating organization charged with developing enforceable reliability rules. It also provides the FERC authority over the transmission systems operated by the federal electric utilities (Tennessee Valley Authority and the other power marketing administrations). H.R. 2944 originally included FERC authority to review mergers and asset sales by electric utilities and transmitting utilities. However, an amendment offered by Rep. Burr (R-NC) eliminated that authority.

The legislation would also repeal the Public Utility Holding Company Act (PUHCA), as well as, Section 210 of the Public Utility Regulatory Policies Act (PURPA), which addresses mandatory purchase obligations. It contains congressional findings that encourage states to address stranded costs, includes no federal renewable portfolio standard but does not prevent states from setting their own standards, and does not mandate Regional Transmission Organization (RTO) formation. These final provisions are similar to most other restructuring legislation introduced during the last year, which are listed below in Exhibit 2 (current to August 7, 2000).

Exhibit 2: Restructuring Legislation Introduced in the 106th Congress

- H.R. 667, Rep. Burr (R-NC)
- S. 516, Sen. Thomas (R-WY)
- H.R. 1587, Rep. Stearns (R-FL)
- S. 1047, the administration's bill, introduced by request by Sens. Murkowski (R-AK) and Bingaman (D-NM)
- H.R. 1828, the administration's bill, introduced by request by Reps. Bliley (R-VA) and Dingell D-MI)
- H.R. 2050, Reps. Largent (R-OK) and Markey (D-MA)
- S. 1273, Sen. Bingaman (D-NM)
- S. 1273, Sen. Nickles (R-OK)
- S. 1369, Sen. Jeffords (R-VT)
- H.R. 2569, Rep. Pallone (D-NJ)
- H.R. 2602, Rep. Wynn (D-MD)
- H.R. 2645, Rep Kucinich (D-OH)
- H.R. 2734, Rep. Brown (D-OH)
- H.R. 2786, Rep. Sawyer (D-OH)
- S. 2098, Sens. Murkowski (R-AK) and Landrieu (D-LA)
- S. 2886, Sens. Gramm (R-TX) and Schumer (D-NY)
- H.R. 4941, Rep. Wynn (D-MD)
- H.R. 4971, Rep Hayworth (R-AZ)
- S. 2904, Sen. Bingaman (D-NM)
- S. 2967, Sen. Murkowski (R-AK)

An issue that has attracted a lot of attention recently because of last summer's high temperatures, blackouts, and volatile energy prices is reliability. Several stand alone reliability measures have been introduced in Congress and one has gone so far as to pass out of the Senate. S. 2071, introduced by Sen. Slade Gorton (R-WA) was approved by unanimous consent on June 30, 2000. It is currently awaiting House action, however, observers feel that unless some kind of energy catastrophe takes place during the remaining days of Congress, no action will be taken.

S. 2071, known as the Electric Reliability 2000 Act, would add a new section to the Federal Power Act which would establish enforceable rules for the use of the interstate transmission grid and create an industry-run, FERC-overseen Electric Reliability Organization (ERO). The ERO sets those rules for the use of the transmission grid for the bulk power system only, but does not have the authority to set or enforce standards for the safety or adequacy of electric facilities or services. The legislation makes it clear that nothing in S. 2071 will preempt the authority of any state to take action to ensure the safety, adequacy, or reliability of electric service within their state, so long as such action is not inconsistent with any ERO-set standard. The North American Electric Reliability Council (NERC) is already working on transforming itself into the North American Electric Reliability Organization (NAERO) to fulfill the requirements of this legislation, should it become law.

Until NAERO is up and running, the existing NERC and the individual regional reliability councils may file existing reliability standards they propose to be mandatory in the interim. The reliability standards established by NAERO and approved by the FERC would be mandatory on all system operators and users of the bulk power system.

The problems California has experienced this summer with rising electricity prices and reliability following the passage of a deregulation measure could indicate either a greater or a fewer number of restructuring bills will be introduced in next year's Congress. Some Congressmen have indicated in the news that the situation in California will likely cause them to be more cautious before approving any sort of Federal restructuring legislation.

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10. LIST OF ACRONYMS

ARP ....Alternative Regulatory Plan
ARTO ....Alliance Regional Transmission Organization
CAC ....Citizens Action Coalition
CPU ....California Public Utility Commission
DOE ....Department of Energy
DSM ....Demand-Side Management
ECAR ....East Central Area Reliability Council
FAC ....Fuel Adjustment Cost Charge
FERC ....Federal Energy Regulatory Commission
G&T ....Generation and Transmission
GCA ....Gas Cost Adjustment
GCIM ....Gas Cost Incentive Mechanism
HE ....Hoosier Energy
I&M ....Indiana Michigan Power Company, subsidiary of AEP
ICC ....Illinois Commerce Commission
IMPA ....Indiana Municipal Power Agency
IOU ....Investor-owned Utility
IPL ....Indianapolis Power and Light
IRP ....Integrated Resource Plan
ISO ....Independent System Operator
IURC ....Indiana Utility Regulatory Commission
KWh ....Kilowatt Hour
LDC ....Local Distribution Company (gas)
MISO ....Midwest Independent System Operator
MPSC ....Michigan Public Service Commission
NAERO ....North American Electric Reliability Organization
NERC ....North American Electric Reliability Council
NIPSCO ....Northern Indiana Public Service Company
OUCC ....Office of Utility Consumer Counselor
PUCO ....Public Utility Commission of Ohio
PSI ....PSI Energy
PUHCA ....Public Utility Holding Company Act 1935
PURPA ....Public Utility Regulatory Policies Act 1978
PX ....Power Exchange
REMC ....Rural Electric Membership Cooperative
RTO ....Regional Transmission Organization
SEC ....Securities and Exchange Commission
SIGECO ....Southern Indiana Gas & Electric Company
T&D ....Transmission and Distribution
WVPA ....Wabash Valley Power Association

11. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Aggregator: An entity that pools customers into a buying group for the purchase of a commodity good or service.

Alternative Regulatory Plan (ARP): In contrast to cost-of-service regulation, alternative regulatory plans are designed to allow the utility more flexibility in pricing energy to customers. ARPs may also contain provisions to streamline the regulatory approval process.

Ancillary Services: Services that must be provided in the generation and delivery of electricity. As identified by the FERC, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and economic dispatch of plants); contractual arrangements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Broker: An agent for others in negotiating contracts, purchases or sales of electricity and associated services without owning any transmission or generation facilities. Unlike a marketer, a broker does not take title to the electricity being bought or sold.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Citygate: A point of delivery to the gas local distribution company from the pipeline.

Convergence Mergers: In the context of energy, mergers between gas and electric utilities.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Cost-of-Service: A term related to the current methods of regulating utilities (both gas and electric). A cost-of-service study analyzes a utility's average costs (also called embedded costs) of facilities and expenses in relationship to its revenues to determine rates (prices) for the customer. This is generally referred to as cost-of-service ratemaking or cost-of-service pricing.

Dekatherm (Dth): A unit of heating value equivalent to 1 million Btus.

Demand-Side Management (DSM): Conservation resource planning that considers factors affecting energy usage for each customer class; generally designed to reduce or shift load.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Earnings Test: An evaluation conducted as part of generating fuel cost adjustments and all gas cost adjustments to determine if the proposed change in fuel or gas costs would result in a utility earning in excess of its allowed net operating income. The actual evaluation is complex, but if the utility is found to be earning more than allowed, the excess revenue is returned to the ratepayers.

Gas Cost Adjustment (GCA): A formal and summary proceeding held quarterly or semi-annually by the IURC for natural gas utilities which allows these utilities to increase or decrease rates based on changes in the price of gas purchased from various sources. Rates are projected for three or six months into the future and "reconciled" from the past with costs from comparable time periods and an "earnings test" is part of the process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Gigawatt-Hour (GWh): One gigawatt of generation for one hour.

Green Power: Term used to describe electricity produced from environmentally friendly or renewable resources, such as solar or wind power; see "Renewable Energy."

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1 kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Local Distribution Company (LDC): The utility that is responsible for delivering gas to the customer behind the citygate (where the pipeline delivers gas to the LDC).

Megawatt (MW): One thousand kilowatts or one million watts.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

North American Electric Reliability Council (NERC): A nonprofit organization formed for the purpose of coordinating electric system operation and planning throughout North America, including Mexico and Canada.

Pancaking: Occurs when a seller attempts to transmit electricity through the control areas of several utilities and must pay a separate transmission charge to each utility.

Power Exchange: An independent entity with no affiliate or financial interest in distribution, transmission or generation companies or facilities. It would match bids submitted by utilities, power marketers, brokers and other participants ranking the bids on a least-cost basis and arrange for the power to be delivered.

Power Marketers: A business entity engaged in buying and selling electricity, but does not own generation or transmission facilities. Power marketers take ownership of the electricity and offer risk management derivative products such as options, swaps, forward contracts and electricity futures.

Public Utility Holding Company Act of 1935 (PUHCA): A federal law that sought to correct abuses of utility holding companies. Holding companies largely confined to a single state or presumed to be susceptible to effective state regulation are "exempt" from federal regulation under PUHCA. Multi-state holding companies must "register" with the SEC and comply with federal regulation under PUHCA.

Public Utility Regulatory Polices Act of 1978 (PURPA): A federal law that requires utilities to buy electric power from private "qualifying facilities" at an avoided cost rate. The avoided cost rate is equivalent to what it would have otherwise cost the utility to generate or purchase the power itself. Utilities must further provide customers who choose to generate their own electricity a reasonably priced back-up supply of electricity.

Registered Holding Company: Any company that acquires more than 10 percent of the equity of a utility and as a consequence, must register with the Securities and Exchange Commission and is subject to all provisions of PUHCA.

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Renewable Energy (Green Power): Naturally replenishable energy resources; includes geothermal, biomass, hydro-electric, solar, tidal action and wind as means of electricity generation.

Senate Enrolled Act 637: Codified as IC 8-1-2.5, this statute enables the IURC to consider alternative regulatory plans, among other things.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

Stranded Costs: Costs associated with assets that prove to be uneconomical in a competitive environment. Because these assets were previously approved by regulatory authorities and included in rates, utilities claim they should be able to fully recover these costs before the transition to customer choice is completed.

Supplier of Last Resort: In a customer choice market, the supplier of last resort will be a designated power supplier that will provide the energy needs of customer who can't or won't choose a supplier

Thirty-Day Filings: Requests for utilities for approval of new rates, changes to nonrecurring charges, altered rules and regulations or changes in periodic trackers. This process is designed to allow these types of requests to be reviewed and approved by the Commission in a more expeditious and less costly manner than a formally docketed case.

Tracker: A regulatory mechanism that allows a utility to pass on (track) to its retail customers on a periodic basis changes in the costs of a selected expense outside the context of a general rate case. Two types of trackers are FACs and GCAs.

Throughput (Gas): Actual or estimated volume of natural gas that may be carried on a pipeline over a period of time.

Transition Costs: Costs resulting from restructuring an industry from a regulatory environment to a competitive environment. Stranded costs are included in transition costs but may not be the only costs incurred.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Transportation (Gas): The transportation of natural gas by a pipeline (upstream of the citygate) and/or by the LDC (behind the citygate).

Unbundling: The process of separating out the package of services offered by an electric or gas company and charging separate rates for each service that fairly represents the cost of providing the service. In the electric industry, these may include: transmission, generation, distribution services, metering, billing, maintenance. In the natural gas industry, in addition to transportation of gas, unbundling may include storage, gathering, balancing services and other items.

Universal Service: A condition that makes a utility service (gas, electricity, telephone, etc.) available to any customer that wants it, at an affordable price.

Vertically Integrated Utilities (companies): An arrangement whereby the same company owns most or all of the facilities necessary for producing, transporting and selling electricity (or gas). Traditionally, vertically integrated electric utilities have owned the generation, transmission and distribution facilities. In some cases, electric utilities have also owned coal mines and gas supplies to increase the level of vertical integration.

12. APPENDICES

Appendix A; Sales, Revenues and Market Share for Indiana Electric Utilities

Appendix B; Analysis of Gas Sales Data

Appendix C; Restructuring Activities by State

Appendix D; Natural Gas Industry Residential Pilot Programs & Unbundling Initiatives

Appendix E; Mergers Filed at the FERC Since 1997

SALES, REVENUES AND MARKET SHARE FOR INDIANA ELECTRIC UTILITIES – 1999 SUMMARY

MWH

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	22,161,332	17,872,605	38,611,958	43,351,329	121,997,224
Rural Electric Membership Corporations	1,187,301	486,511		13,183	1,686,995
Municipal Electric Utilities	1,387,122	3,589,015		81,112	5,057,249
Totals	**24,735,755**	**21,948,131**	**38,611,958**	**43,445,624**	**128,741,468**

REVENUE (000s)

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	$1,556,884	$1,094,944	$1,588,307	$1,365,447	$5,605,582
Rural Electric Membership Corporations	82,086	26,687		1,890	110,663
Municipal Electric Utilities	84,729	171,592		30,932	287,253
Totals	**$1,723,699**	**$1,293,223**	**$1,588,307**	**$1,398,269**	**$6,003,498**

RETAIL MARKET SHARE BY MWH

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	89.59%	81.43%	100.00%	99.78%	94.76%
Rural Electric Membership Corporations	4.80%	2.22%	-	0.03%	1.31%
Municipal Electric Utilities	5.61%	16.35%	-	0.19%	3.93%

RETAIL MARKET SHARE BY REVENUES

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Investor Owned Electric Utilities	90.32%	84.67%	100.00%	97.65%	93.37%
Rural Electric Membership Corporations	4.76%	2.06%	-	0.14%	1.84%
Municipal Electric Utilities	4.92%	13.27%	-	2.21%	4.78%

INVESTOR-OWNED ELECTRIC UTILITIES - 1999 DATA

MWH

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Indiana Michigan Power Company	5,351,392	4,668,172	8,236,177	7,664,668	25,920,409
Indianapolis Power & Light Company	4,569,948	1,951,906	7,253,760	2,074,162	15,849,776
Northern Indiana Public Service Company	2,996,650	3,293,898	9,198,315	2,725,731	18,214,594
PSI Energy, Inc.	7,871,763	6,654,621	11,507,716	29,037,631	55,071,731
Southern Indiana Gas & Electric Company	1,371,579	1,304,008	2,415,990	1,849,137	6,940,714
Totals	**22,161,332**	**17,872,605**	**38,611,958**	**43,351,329**	**121,997,224**

REVENUE (000s)

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Indiana Michigan Power Company	$377,786	$290,833	$364,6067	$309,099	$1,342,325
Indianapolis Power & Light Company	282,254	127,027	328,904	51,553	789,737
Northern Indiana Public Service Company	294,223	275,368	416,176	88,473	1,074,239
PSI Energy, Inc.	511,821	331,813	399,091	854,488	2,097,212
Southern Indiana Gas & Electric Company	90,800	69,905	79,531	61,833	302,069
Totals	**$1,556,884**	**$1,094,944**	**$1,588,307**	**$1,365,447**	**$5,605,582**

AVERAGE RATE PER KWH

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER	TOTAL
Indiana Michigan Power Company	$0.07	$0.06	$0.04	$0.04	$0.05
Indianapolis Power & Light Company	0.06	0.07	0.05	0.02	0.05
Northern Indiana Public Service Company	0.10	0.08	0.05	0.03	0.06
PSI Energy, Inc.	0.07	0.05	0.03	0.03	0.04
Southern Indiana Gas & Electric Company	0.07	0.05	0.03	0.03	0.04

RETAIL MARKET SHARE

UTILITY	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	OTHER
Indiana Michigan Power Company	28.14%	21.67%	27.16%	23.03%
Indianapolis Power & Light Company	35.74%	16.08%	41.65%	6.53%
Northern Indiana Public Service Company	27.39%	25.63%	38.74%	8.24%
PSI Energy, Inc.	24.40%	15.82%	19.03%	40.74%
Southern Indiana Gas & Electric Company	30.06%	23.14%	26.33%	20.47%

RURAL ELECTRIC MEMBERSHIP CORPORATIONS – 1999 DATA

KWH

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Fulton County REMC	62,434,395	12,842,380	4,546,129	79,822,904
Harrison County REMC	270,989,533	139,724,879	1,930,356	412,644,768
Jackson County REMC	314,257,175	64,693,419	4,355,281	383,305,875
Marshall County REMC	63,088,098	14,669,287	1,256,070	79,013,455
Newton County REMC	15,111,607	9,187,527	280,427	24,579,561
Northeastern REMC	251,741,076	181,268,675	814,284	433,824,035
Utilities District of Western Indiana REMC	209,678,817	64,124,671	-	273,803,488
Totals	1,187,300,701	486,510,838	13,182,547	1,686,994,086

REVENUE

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Fulton County REMC	$4,276,285	$867,470	$310,287	$5,454,042
Harrison County REMC	17,041,699	6,731,955	489,247	24,262,901
Jackson County REMC	23,157,517	4,030,346	481,090	27,668,953
Marshall County REMC	5,330,626	1,033,097	173,408	6,537,131
Newton County REMC	1,109,129	592,084	31,467	1,732,680
Northeastern REMC	17,067,738	9,871,485	144,438	27,083,661
Utilities District of Western Indiana REMC	14,102,462	3,560,274	260,095	17,922,831
Totals	$82,085,456	$26,686,711	$1,890,032	$110,662,199

AVERAGE RATE PER KWH

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Fulton County REMC	$0.07	$0.07	$0.07	$0.07
Harrison County REMC	0.06	0.05	0.25	0.06
Jackson County REMC	0.07	0.06	0.11	0.07
Marshall County REMC	0.08	0.07	0.14	0.08
Newton County REMC	0.07	0.06	0.11	0.07
Northeastern REMC	0.07	0.05	0.18	0.06
Utilities District of Western Indiana REMC	0.07	0.06	-	0.07

RETAIL MARKET SHARE

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
Fulton County REMC	78.41%	15.91%	5.69%
Harrison County REMC	70.24%	27.75%	2.02%
Jackson County REMC	83.69%	14.57%	1.74%
Marshall County REMC	81.54%	15.80%	2.65%
Newton County REMC	64.01%	34.17%	1.82%
Northeastern REMC	63.02%	36.45%	0.53%
Utilities District of Western Indiana REMC	78.68%	19.86%	1.45%

MUNICIPAL ELECTRIC UTILITIES – 1999 DATA

KWH

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Anderson Municipal Light & Power	306,185,558	409,150,369	4,564,592	719,900,519
Auburn Municipal Electric	53,442,424	483,614,360	-	537,056,784
Bargersville Municipal Power & Light	26,693,341	18,172,128	1,354,451	46,219,920
Boonville Municipal Light & Power	31,442,786	33,522,564	-	64,965,350
Centerville Municipal Power & Light	13,594,582	7,655,941	1,478,361	22,728,884
Columbia City Municipal Electric	33,253,786	76,276,948	2,588,303	112,119,037
Covington Municipal Electric	12,811,869	11,043,982	-	23,855,851
Crawfordsville Municipal Electric Light & Power	73,441,801	315,698,573	10,867,450	400,007,824
Edinburgh Municipal Electric	21,762,547	67,682,972	1,061,851	90,507,370
Frankfort City Light & Power	71,125,091	256,348,417	2,619,196	330,092,704
Frankton Municipal Electric	17,366,171	-	-	17,366,171
Garrett Municipal Electric	NA	NA	NA	NA
Greenfield Municipal Electric	55,801,910	176,219,479	2,938,186	234,959,575
Kingsford Heights Municipal Electric	5,184,372	-	-	5,184,372
Knightstown Municipal Electric	12,479,882	9,042,856	723,400	22,246,138
Lawrenceburg Municipal Electric	25,793,821	67,394,399	964,356	94,152,576
Lebanon Municipal Electric	59,586,176	108,769,182	2,872,101	171,227,459
Logansport Municipal Electric	95,283,666	285,797,541	2,552,087	383,633,294
Mishawaka Municipal Electric	165,568,515	363,571,586	25,181,325	554,321,426
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	195,361,450	738,457,764	11,123,828	944,943,042
South Whitley Municipal Electric	NA	NA	NA	NA
Straughn Municipal Electric	1,276,120	-	-	1,276,120
Tipton Municipal Electric	34,474,734	69,945,829	936,346	105,356,909
Troy Municipal Electric	9,752,850	-	-	9,752,850
Washington City Municipal Light & Power	65,438,981	90,650,479	9,286,587	165,376,047
Totals	**1,387,122,433**	**3,589,015,369**	**81,112,420**	**5,057,250,222**

REVENUES

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Anderson Municipal Light & Power	$19,453,828	$20,523,502	$808,940	$40,786,270
Auburn Municipal Electric	2,715,534	23,090,877	196,837	26,003,248
Bargersville Municipal Power & Light	1,729,202	1,125,457	145,610	3,000,269
Boonville Municipal Light & Power	2,143,493	2,085,727	205,568	4,434,788
Centerville Municipal Power & Light	643,151	413,777	75,537	1,132,465
Columbia City Municipal Electric	2,137,948	4,359,071	199,971	6,696,990
Covington Municipal Electric	813,951	668,436	95,945	1,578,332
Crawfordsville Municipal Ele. Light & Power	4,638,358	14,022,715	2,179,533	20,840,606
Edinburgh Municipal Electric	1,244,356	3,599,196	73,580	4,917,132
Frankfort City Light & Power	4,219,213	10,704,818	409,165	15,333,196
Frankton Municipal Electric	922,340	-	6,324	928,664
Garrett Municipal Electric	NA	NA	NA	NA
Greenfield Municipal Electric	3,196,198	7,935,111	560,334	11,691,643
Kingsford Heights Municipal Electric	267,131	70,625	89,909	427,665
Knightstown Municipal Electric	682,430	504,141	36,481	1,223,052
Lawrenceburg Municipal Electric	1,430,161	3,581,620	103,770	5,115,551
Lebanon Municipal Electric	3,651,118	5,764,831	181,057	9,597,006
Logansport Municipal Electric	6,132,648	14,154,907	298,841	20,586,396
Mishawaka Municipal Electric	11,428,272	20,303,616	2,197,867	33,929,755
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	11,186,810	30,466,130	22,307,762	63,960,702
South Whitley Municipal Electric	NA	NA	NA	NA
Straughn Municipal Electric	73,335	7,583	7,959	88,877
Tipton Municipal Electric	1,981,116	3,548,068	94,448	5,623,632
Troy Municipal Electric	214,451	370,555	33,533	618,539
Washington City Municipal Light & Power	3,824,490	4,291,702	622,583	8,738,775
Totals	**$84,729,534**	**$171,592,465**	**$30,931,554**	**$287,253,553**

AVERAGE RATE PER KWH

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER	TOTAL
Anderson Municipal Light & Power	$0.06	$0.05	$0.18	$0.06
Auburn Municipal Electric	0.05	0.05	-	0.05
Bargersville Municipal Power & Light	0.06	0.06	0.11	0.06
Boonville Municipal Light & Power	0.07	0.06	-	0.07
Centerville Municipal Power & Light	0.05	0.05	0.05	0.05
Columbia City Municipal Electric	0.06	0.06	0.08	0.06
Covington Municipal Electric	0.06	0.06	-	0.07
Crawfordsville Municipal Ele. Light & Power	0.06	0.04	0.20	0.05
Edinburgh Municipal Electric	0.06	0.05	-	0.05
Frankfort City Light & Power	0.06	0.04	0.16	0.05
Frankton Municipal Electric	0.05	-	-	0.05
Garrett Municipal Electric	NA	NA	NA	NA
Greenfield Municipal Electric	0.06	0.05	0.19	0.05
Kingsford Heights Municipal Electric	0.05	-	-	0.08
Knightstown Municipal Electric	0.05	0.06	0.05	0.05
Lawrenceburg Municipal Electric	0.06	0.05	0.11	0.05
Lebanon Municipal Electric	0.06	0.05	0.06	0.06
Logansport Municipal Electric	0.06	0.05	0.12	0.05
Mishawaka Municipal Electric	0.07	0.06	0.09	0.06
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA	NA
Richmond Municipal Power & Light	0.06	0.04	2.01	0.07
South Whitley Municipal Electric	NA	NA	NA	NA
Straughn Municipal Electric	0.06	-	-	0.07
Tipton Municipal Electric	0.06	0.05	0.10	0.05
Troy Municipal Electric	0.02	-	-	-
Washington City Municipal Light & Power	0.06	0.05	0.07	0.05

RETAIL MARKET SHARE

UTILITY	RESIDENTIAL	COMMERCIAL & INDUSTRIAL	OTHER
Anderson Municipal Light & Power	47.70%	50.32%	1.98%
Auburn Municipal Electric	10.44%	88.80%	0.76%
Bargersville Municipal Power & Light	57.63%	37.51%	4.85%
Boonville Municipal Light & Power	48.33%	47.03%	4.64%
Centerville Municipal Power & Light	56.79%	36.54%	6.67%
Columbia City Municipal Electric	31.92%	65.09%	2.99%
Covington Municipal Electric	51.57%	42.35%	6.08%
Crawfordsville Municipal Ele. Light & Power	22.26%	67.29%	10.46%
Edinburgh Municipal Electric	25.31%	73.20%	1.50%
Frankfort City Light & Power	27.52%	69.81%	2.67%
Frankton Municipal Electric	99.32%	0.00%	0.68%
Garrett Municipal Electric	NA	NA	NA
Greenfield Municipal Electric	27.34%	67.87%	4.79%
Kingsford Heights Municipal Electric	62.46%	16.51%	21.02%
Knightstown Municipal Electric	55.80%	41.22%	2.98%
Lawrenceburg Municipal Electric	27.96%	70.01%	2.03%
Lebanon Municipal Electric	38.04%	60.07%	1.89%
Logansport Municipal Electric	29.79%	68.76%	1.45%
Mishawaka Municipal Electric	33.68%	59.84%	6.48%
Paoli Municipal Electric	NA	NA	NA
Peru Municipal Electric Light & Power	NA	NA	NA
Richmond Municipal Power & Light	17.49%	47.63%	34.88%
South Whitley Municipal Electric	NA	NA	NA
Straughn Municipal Electric	82.51%	8.53%	8.96%
Tipton Municipal Electric	35.23%	63.09%	1.68%
Troy Municipal Electric	34.67%	59.91%	5.42%
Washington City Municipal Light & Power	43.76%	49.11%	7.12%

ANALYSIS OF GAS SALES DATA FOR 1997, 1998 & 1999

CITIZENS GAS & COKE UTILITY

	1999	1998	1997
Revenues By Customer Class			
Residential	$ 142,642,436	$ 139,788,095	$ 160,695,010
Commercial & Industrial	68,214,515	68,033,459	96,813,518
Other	1,313,594	(3,553,278)	3,019,648
Totals	**$ 212,170,545**	**$ 204,268,276**	**$ 260,528,176**
Sales By Customer Class in Dth			
Residential	23,301,309	21,471,821	26,392,624
Commercial & Industrial	14,805,666	13,531,926	21,857,492
Other	3,791,803	(506,300)	374,100
Totals	**41,898,778**	**34,497,447**	**48,624,216**
Revenues Per Dth			
Residential	$ 6.1216	$ 6.5103	$ 6.0886
Commercial & Industrial	$ 4.6073	$ 5.0276	$ 4.4293
Other	$ 0.3464	$ 7.0181	$ 8.0718
Average Rate	$ 5.0639	$ 5.9213	$ 5.3580

INDIANA GAS COMPANY, INC.

	1999	1998	1997
Revenues By Customer Class			
Residential	$ 283,838,041	$ 274,164,168	$ 335,787,421
Commercial & Industrial	114,232,782	125,575,381	172,341,621
Other	(3,943,023)	-	-
Totals	**$ 394,127,800**	**$ 399,739,549**	**$ 508,129,042**
Sales By Customer Class in Dth			
Residential	43,943,000	38,806,564	48,208,746
Commercial & Industrial	23,990,000	23,998,579	32,934,928
Other	(950,000)	-	-
Totals	**66,983,000**	**62,805,143**	**81,143,674**
Revenues Per Dth			
Residential	$ 6.4592	$ 7.0649	$ 6.9653
Commercial & Industrial	$ 4.7617	$ 5.2326	$ 5.2328
Other	$ 4.1506	$ -	$ -
Average Rate	$ 5.8840	$ 6.3648	$ 6.2621

NORTHERN INDIANA PUBLIC SERVICE CO.

Revenues By Customer Class	1999	1998	1997
Residential	$ 361,206,716	$ 327,901,804	$ 439,103,630
Commercial & Industrial	151,862,365	148,765,570	222,825,282
Other	78,322,348	45,172,940	38,728,179
Totals	**$ 591,391,429**	**$ 521,840,314**	**$ 700,657,091**
Sales By Customer Class in Dth			
Residential	65,168,000	58,346,000	73,452,000
Commercial & Industrial	32,151,000	34,200,000	44,857,000
Other	34,468,000	22,795,000	13,887,000
Totals	**131,787,000**	**115,341,000**	**132,196,000**
Revenues Per Dth			
Residential	$ 5.5427	$ 5.6200	$ 5.9781
Commercial & Industrial	$ 4.7234	$ 4.3499	$ 4.9675
Other	$ 2.2723	$ 1.9817	$ 2.7888
Average Rate	$ 4.4875	$ 4.5243	$ 5.3001

SOUTHERN INDIANA GAS & ELECTRIC CO.

Revenues By Customer Class	1999	1998	1997
Residential	$ 45,254,410	$ 47,956,612	$ 55,679,900
Commercial & Industrial	18,397,732	19,028,906	25,480,297
Other	175,015	194,621	2,663,430
Totals	**$ 63,827,157**	**$ 67,180,139**	**$ 83,823,627**
Sales By Customer Class in Dth			
Residential	8,566,559	7,924,707	9,653,802
Commercial & Industrial	4,130,263	3,914,622	5,366,554
Other	(426,930)	(223,594)	(194,892)
Totals	**12,269,892**	**11,615,735**	**14,825,464**
Revenues Per Dth			
Residential	$ 5.2827	$ 6.0515	$ 5.7677
Commercial & Industrial	$ 4.4544	$ 4.8610	$ 4.7480
Other	$ (0.4099)	$ (0.8704)	$ (13.6662)
Average Rate	$ 5.2019	$ 5.7835	$ 5.6540

COMBINED ANALYSIS OF GAS SALES DATA

CITIZENS GAS, INDIANA GAS, NIPSCO AND SIGECO

	1999	1998	1997
Total Sales by Class (1,000 Dth)			
Residential	140,748	126,229	157,707
Commercial	53,958	52,061	67,788
Industrial	20,972	23,382	37,228
Other	33,109	22,586	14,066
Total	**248,787**	**224,259**	**276,789**
Total Transportation by Class (1,000 Dth)			
Residential	995	207	-------
Commercial	12,971	10,188	6,908
Industrial	252,987	238,738	219,229
Other	4,152	2,938	772
Total	**271,105**	**252,069**	**226,909**
Total Throughput by Class (1,000 Dth)			
Residential	141,743	126,436	157,707
Commercial	66,929	62,250	74,695
Industrial	273,959	262,117	256,458
Other	37,261	25,525	14,839
Total	**519,892**	**476,328**	**503,699**
Percent Transportation to Throughput			
Residential	0.70%	0.16%	0.00%
Commercial	19.38%	16.37%	9.25%
Industrial	92.34%	91.08%	85.48%
Other	11.14%	11.51%	5.20%
Total	**52.15%**	**52.92%**	**45.05%**

RESTRUCTURING ACTIVITIES BY STATE

Alabama: The Alabama Public Service Commission continued its investigation into restructuring in the electric utility industry (Docket No. 26427) by conducting hearings April 17-18, 2000. Interested parties were allowed to make 10-minute presentations on the key issue of whether electricity restructuring is in the public interest in Alabama and the PSC's role of regulation and jurisdiction over the complex issue.

Following the hearing, parities were allowed to submit follow-up comments. The Alabama PSC received comments from the Attorney General's Office of Alabama, Alabama Industry and Manufacturers Association, Alabama Power Company, Alabama Municipal Electric Authority/Electric Cities of Alabama and Alabama Rural Electric Association/Alabama Electric Cooperative.

The Attorney General's comments generally supported a cautious move toward restructuring the Alabama Electric industry. The Alabama Industry and Manufacturers Association recommended that the Commission require Alabama Power Company to unbundle rates into generation and transmission/distribution components. It also recommended that the Commission preliminarily conclude that retail competition would be in the public interest and then initiate a process to address specific restructuring issues or topics.

Alabama Power Company, while not rejecting the possibility of retail competition, suggested that the Commission first take full advantage of wholesale competition before proceeding to initiate retail competition. The Company cited the state's low retail rates and high service reliability as reasons for proceeding with caution. Finally, the Company stated that if the Commission decided to implement retail competition, it should follow a market-driven model and avoid re-regulating the industry.

The Alabama Municipal Electric Authority/Electric Cities asserted their self-regulating, self-determination authority, which allows these entities to determine the best interest of their citizens.

To date, nothing further has been issued by the Alabama Public Service Commission in this investigation.

Alaska: On April 5, 1999 a report on electric utility restructuring in Alaska was presented to the Alaska Public Utilities Commission and the Alaska State Legislature. The report, prepared by the combined efforts of CH2M Hill and Econergy International Corporation, made the following recommendations:

- Continue and expand efforts to improve rural system efficiencies through aggregation of administrative, fuel-purchasing, operations, logistical and other appropriate functions among geographically separate but proximate villages.
- In order to build experience in the use and deployment of distributed energy systems which offer potential long-term cost savings, consider the creation of a pilot program based on technology demonstration and deployment, conducted in coordination with government and non-government organizations.
- Initiate a specific set of market-friendly regulatory reforms today in order to bring the real competitive opportunity into focus.
- Complete a regulator agenda that –
    - calculates and allocates component costs for Railbelt utilities in a rational and uniform manner (unbundling and cost allocation);
    - rationalizes access to, and governance of, the transmission system to create a non-discriminatory open access network while ensuring reliability;
    - rationalizes oversight of generation siting and construction to minimize stranded cost exposure and to foster the emergence of a competitive wholesale market with new merchant generators; and

- Implements central dispatch/power pooling recommendation of the October 1998 Black & Veatch study in the Railbelt to harvest near-term savings and to facilitate emergence of a competitive wholesale market over the longer term.
- Maximize potential for market success –
  - Mitigate regulatory and structural inefficiencies to produce near-term savings and encourage efficient market behavior.
  - Design pilot and retail competition to encourage technology-based competition and to realize the potential for technological innovation to reduce costs.
  - Design efficient commodity markets to enable value-added service innovation.
  - Exploit Alaska's small electricity systems to lead the industry trend toward new, modular distributed systems.
  - Harmonize restructuring agendas in telecommunications, natural gas, and electricity to realize convergence benefits.
- Any market, regardless of size and scope, must carry its own administrative and oversight costs.
- To increase market liquidity, consider a BTU Exchange, e.g., create a market exchange where both gas and electricity are traded as BTU contracts.
- Consider retail market simulation modeling as part of the decision to move to full retail competition pilot or retail competition.
- Modeling and simulation must precede full retail market opening in any case.

There have been no further restructuring activities in Alaska since the release of this report.

Arizona: In the fall of 1999, the Arizona Corporation Commission finalized restructuring settlements with Arizona Public Service and Tucson Electric Power that would begin implementation of customer choice in October 2000.

In January 2000, the competition plan for Arizona Public Service came under attack by the Phoenix-based Center for Law in the Public Interest and Houston-based Enron Corp. Each separately filed lawsuits in Arizona's court challenging the details of the settlement agreement between the ACC and APS.

That agreement called for the end-user rate decrease of 7.5% over the next five years and stranded cost recovery for APS of about $350 million.

The agreement also allows APS to retain ownership of its generating assets, 3,973 MW of coal and nuclear-fired generation. APS will keep the generation, but must spin it off into a separate affiliate. The new affiliate must operate independently of the other functions of the company. The agreement also opens part of APS' market to competition, starting October 1, 2000. The utility's market will be fully opened to competition by January 1, 2001.

The Center and Enron Corp. each claim the settlement is illegal and should be nullified. The Center argues that the financial condition of APS was not fully examined by the ACC and had the utility's records been thoroughly analyzed, the rate cut ordered by the ACC would exceed 7.5%. The Center claimed state law requires such an analysis when determining new utility rates.

Enron said it filed legal action after the ACC denied its request for rehearing on the settlement. The company, one of several trying to break into the Arizona power market, claims the possibility of a relationship between APS' generating arm and its other electricity businesses might give the company an unfair advantage. The amount of consumer shopping credits is also an issue with Enron.

Arizona Public Service said it anticipated the suits from both parties, but the suits should not delay either the rate cuts planned or the opening of the power market.

The Arizona Corporation Commission approved a similar agreement for Tucson Electric Power Company in late November 1999, and it, too, could come under attack. To date, no suit has been filed against the settlement.

In a further restructuring development in Arizona, Phoenix-based Salt River Project boosted opportunities for competition in its service territory by increasing the utility's shopping credit by a factor of $86 million and lowering its electricity distribution price.

In addition, the utility decided to open its entire market to competition effective May 31, 2000. This made all of SRP's 710,000 customers eligible for competition. Originally, only 20%, about 80,000 SRP residential, business and industrial customers had a choice of generation suppliers.

SRP said the change makes it the first public power entity in the nation to open its entire service area to competition. The change also put the utility approximately seven months ahead of the schedule mandated by the Arizona Legislature, the state entity that controls SRP activity.

Arkansas: The Arkansas Legislature on April 8, 1999 completed work on a major restructuring bill, which calls for the start of retail choice in the state as early as 2002. Governor Mike Huckabee signed the measure on April 15, 1999.

In general, the bill orders the Public Service Commission (PSC) to begin retail choice for all users on January 1, 2002. But it can delay the start up to January 1, 2003, if it decides the utilities are not ready.

The bill gives the PSC power to control market power but not to force asset divestiture except in extreme cases. The PSC also will receive wide powers to determine stranded costs and set transition charges.

The bill also gives cooperatives some protection against losing customers to municipal utilities during a four-year period after competition begins.

In another key provision, the bill leaves open whether the state will use an Independent System Operator or a privately owned transco to manage the transmission grid. Entergy has just filed a formal proposal for a transco with the FERC. The Arkansas bill essentially leaves it to Federal Energy Regulatory Commission to decide whether a transco can be used.

The PSC has been addressing the various issues and rulemakings necessary for the implementation of electric utility restructuring. The Commission's first progress report to the Legislature is due January 15, 2001. The Commission has requested comments and information on current retail electric rates, the wholesale electric market and competitive benefits from all interested parties by August 25, 2000 for incorporation into the first progress report.

California: The electric industry has come under intense scrutiny recently due primarily due to two critical events; the rolling black out in the San Francisco Bay area in June and the skyrocketing electric prices experienced by customers of San Diego Gas & Electric this summer.

The California Independent System Operator ordered Pacific Gas & Electric June 14 to activate a rolling blackout of 100 MW to firm power customers in the San Francisco Bay Area after statewide power reserves dipped below 7 percent for a second straight day. The ISO was compelled to institute the rolling blackout in the Bay Area since the power shortage was localized problem confined to that region.

The power shortage was caused in part because a unit at the Moss Landing Power Plant on the Monterey Bay Peninsula had been taken offline for routine maintenance and repairs. The Moss Landing plant provides voltage support to the Bay Area, which is constrained by a severe transmission shortage on the amount of power that can be imported into the area.

In July 1999, San Diego Gas & Electric (SDG&E) completed its recovery of transition costs and as a result ended its retail rate freeze mandated by the state restructuring law. SDG&E then began passing along to customers the cost of power purchased from the California Power Exchange (PX). This caused electricity prices to consumers to skyrocket this summer as demand drove up the cost of power from the PX.

As a result of these two events the California ISO and PX and SDG&E have come under the scrutiny of lawmakers and regulatory officials. The Mayor of San Diego, Susan Golding, made and official request to the state's Attorney General to investigate the causes of the escalating electricity prices in the area and California Attorney General Bill Lockyer has agreed to open such an investigation. Lockyer's office said it would conduct a broad investigation into the reasons behind price spikes and would seek punishment for any companies or individuals that have acted illegally.

Further, the California Senate plans to hold hearings on retooling the state's electric restructuring law to prevent future price spikes like those that have plagued San Diego customers this summer. The political fallout from the skyrocketing electricity prices in San Diego has prompted some lawmakers from the area to call for scrapping the new market structure altogether in favor of "re-regulation" of the industry. Some lawmakers – including Sen. Steve Peace, the architect of the state's electric restructuring law – have accused out-of-state generators of profiting at the expense of California electricity consumers.

As a result of the rolling blackout in the San Francisco Bay area, the California Electricity Oversight Board issued a subpoena ordering the California Independent System Operator to release confidential market information about generators and other market participants.

The ISO withheld the data because generators feared that their competitors would gain access to commercially sensitive information about their production, bidding patterns and other trade secrets. The ISO's tariff contains a provision requiring that market participants agree before confidential information may be released to a public agency or another party.

Governor Gray Davis ordered the Oversight Board and the California Public Utilities Commission to submit a joint investigative report on the causes of the blackout, including market conditions and maintenance schedules. The Oversight Board is focusing on market analysis and ISO control room operations while the PUC is investigating the utilities' response to the power shortage and implementation of the outage.

At this time the various investigations are still on-going and no specific action has been taken.

Colorado: In their final vote, following 18 months of study and debate, the 29-member Colorado Electric Advisory Panel voted against recommending deregulation of the state's electricity industry to the Colorado Legislature, the body that created the panel.

Panel members claimed deregulation of the state's electricity industry would mean higher prices for consumers. The findings will be contained in a formal report to the Legislature. Opponents of deregulation in the Legislature are expected to use the document to quash any move in the coming session to open the state's power sector. Deregulation is strongly favored by the state's largest electric utility, Public Service Colorado, but opposed by most rural cooperatives across the state. Although it favors deregulation, it is Public Service's huge market share that frightened panel members away from recommending changes. The utility holds a 70% market share in the state, which enjoys relatively low electricity rates. Without the existing controls on electricity prices, the utility would be free in a competitive environment to increase those prices, the panel said.

Many of the panel's conclusions were based on a controversial analysis by engineering firm Stone & Webster, which also suggested the significant market share of Public Service would thwart competitors.

Colorado power rates are already low when compared to other Western states and low rates dull profit opportunities for other suppliers, Stone & Webster said.

Connecticut: The Connecticut Department of Public Utility Control, citing possible conflicts of interest, has given Northeast Utility marketing subsidiary Select Energy only provisional license through June 30, 2000 to sell energy to retail customers in Connecticut.

It will rule on a permanent licenses after investigating whether Select violated state rules on sharing employees and data with affiliate Connecticut Light & Power – also a subsidiary of Northeast Utilities.

In a draft decision the DPUC proposed granting only a three-month provisional license but changed that to six months in the final order issued December 16, 1999, (Docket No. 99-08-03).

The final order also included a provision proposed in the draft banning Select from doing business until further notice with 3,500 retail customers about whom it had received data from CP&L.

In the final order the DPUC said that it believed Select might be violating the state code of conduct on affiliate operations because it was sharing several executives with CP&L through a corporate service group. The commission also said there were another 150 Select employees whose role with CP&L was unclear and therefore the DPUC could not determine whether Select was in compliance with state rules.

It said that during the investigation, Select should retain its current executives to maintain managerial capability but must also report any job changes to the department 10 before the changes are made and provide strict auditing of expenses to insure costs were not shifted to CP&L.

On the customer data issue, the DPUC complained that CP&L made data available to Select before Select received its license to sell energy, which violates state rules. It said it would investigate whether CP&L obtained releases to provide data to Select.

The DPUC said it remained "extremely concerned" that Select may have been improperly provided with customer information.

While the new order clears the way for Select to begin selling energy to retail users in Connecticut when retail choice starts January 1, 2000, it will not be able to deal with the 3,5000 customers with whom it had already made marketing contacts and will also have to inform all customers that it is operating on a six month license.

At least four other marketers and several aggregators are currently hoping to receive licenses to sell retail power in the state.

As of July 1, 2000, all electric consumers have the choice of supplier. Connecticut's electric restructuring seems to be proceeding without incident although it is unclear at this time how many customers are opting to switch to alternative electric suppliers.

Delaware: Delaware Gov. Thomas Carper signed HB-10 that will begin retail competition on October 1, 1999 and phase-in the change by early 2001. HB 10 calls for retail competition to open on October 1, 1999, for Conectiv customers with loads of at least 1 MW. Conectiv users of at least 200 kW would be able to shop for supplies starting February 1, 2000, while smaller consumers would gain access to the market on August 1, 2000. The schedule would run six months' later for Delaware Electric Cooperative (DEC). The bill does not cover municipal utilities, though they could introduce competition at their own timetables.

Conectiv, which includes the former Delmarva Power and serves most customers in the state, has not incurred high stranded costs in Delaware because it has limited nuclear investments and no major independent power contracts, explained Bruce Burcat, executive director of the PSC. Therefore the company would only recover $18-million in restructuring costs, and these would be collected only from large commercial and industrial customers – another concession to small consumers.

The bill would also cut rates 7.5% for Conectiv residential customers, starting October 1, 1999, and would freeze those rates for four years. Larger users would only receive a rate freeze, running three years. In DEC territory, all customers would be covered by a five-year rate freeze, but would receive no rate cuts, since the co-op recently enacted a 5% reduction.

At the end of the four-year transition period, the PSC could open bidding to replace Conectiv as the default generation supplier for customers that do not select outside marketers. If it does not open such bidding, it will require the utility to provide generation at market prices, explained Burcat of the PSC.

A number of consumer benefits are included in the bill as well, including licensing of power suppliers by the PSC, consumer education on electricity choice, $800,000 in annual funding for low-income customers, $800,000 annually for energy conservation and environmental incentive programs and PSC authority to curb market power.

Florida: Governor Jeb Bush has appointed 13 of the 17 member to the Florida Energy Study Commission, which will consider the state's energy policy, including utility deregulation.

The governor promised to establish the Energy 2020 Study Commission and appoint all but four members, after the state Legislature failed to pass bills to establish a similar commission during the spring session.

The governor's commission is scheduled to make its recommendations to the governor and the state legislature on December 1, 2002.

"Florida needs an energy strategy," Bush said. "Over the next 20 years, the quality of life, the quality of our business climate and the quality of our environment will be closely linked with how we address Florida's energy needs. It is appropriate for the state to strategically plan for our future in this area."

None of the members appointed by the governor have any connections to the utility industry, regulated or unregulated. A spokeswoman for the governor explained, "the governor did look for wide representative group of individuals that didn't have any direct control in the utility industry, a group that would be very open minded in its considerations, so there would be no major conflicts to deal with. However, he was looking for a commission that would be diverse in terms of background, regions of the state and environmental issues, which were factored in by way of a couple of the appointments."

The state House and Senate will each name two members. Once those appointments have been made, a date for the first meeting will be scheduled sometime in September.

"As a state that continues to grow, we have a responsibility to provide a reasonable and reliable source of energy – one that respects consumers as well as our natural treasures. The Energy 2020 Study Commission provides the framework for an appropriate energy planning process and policy, and I expect members of the Commission to ensure sensitivity to the interests of both consumers and stakeholders," Bush said.

Of the 13 Bush appointees, six are from the business community, three are attorneys, two are current or former state office holders, one member of the media and one retired. The chairman of the state Public Service Commission will serve in an advisory capacity as a non-voting member of the commission. In addition, David Struhs, Secretary of the state Department of Environmental Protection, was one of Bush's 13 selections.

The issues to be studied by the commission include: Current and future reliability of electric and natural gas supply; emerging energy supply and delivery options; electrical industry competition; environmental impacts of energy supply; energy conservation and fiscal impacts of energy options on taxpayers and energy providers.

Georgia: July 23, 1998, the Georgia Public Service Commission has ordered two Southern Company affiliates - Georgia Power and Savannah Electric & Power - to analyze how industry restructuring will impact their 10-year integrated resource plans and future investment decisions. (Docket No. 98-8708-U, 98-8709-U)

The PSC also asked Georgia Power to submit a report within 90 days on how the state transmission system will handle new power flows created by deregulation and said both companies should delay implementing cuts in reserve margins until the commission completes a restructuring-related study of reliability issues.

Under Georgia law, the two utilities must submit updated integrated resource plans every three years and seek approval by the PSC. In return, they have the right to ask for PSC pre-approval for spending on new resource acquisitions.

The two companies submitted proposed IRPs in February 1998, but the PSC staff complained that the ten-year plans ignored the fact that the Georgia energy market was likely to be deregulated within that time frame, resulting in a major impact on the need for new resources.

So far the debates on restructuring in Georgia, the Southern Company affiliates have called for delay saying the state already has low prices and does not need retail competition. The PSC is just beginning a formal investigation of the issue and the state legislature is not expected to consider a restructuring bill until 2000 at the earliest.

In the filings to the PSC, company representatives said that the issue of restructuring was irrelevant to the planning effort and that they did not want to submit internal company data on the possible affects of decontrol.

The PSC decided against a staff proposal to bar the companies from collecting stranded costs on new investments if they failed to carry out the studies. PSC members said they were not sure they had legal authority for such a step.

On the reserve margin issue, staff complained that the two companies planned to reduce margins by 1.5% to 12.6% despite a June spike in Georgia power demand which almost forced the company to start cutting back supply. They said such a low level would also be out of line with neighboring utilities.

There has been no further action on electric restructuring in Georgia since this order was issued.

Hawaii: In April 1999, both houses of the state legislature approved a resolution asking the Public Service Commission to report on the status of its restructuring investigation. In November 1998, a collaborative of 12 stakeholder groups reported to the Public Service Commission that they failed to reach a consensus on basic aspects of comprehensive industry restructuring.

As the 1999 legislative session adjourned, both houses of the state legislature passed a resolution requesting a report from the PSC on the status of its restructuring investigation. The report is due by January 2000, when the next session begins.

It is unclear whether the Public Service Commission submitted the report or what the report might have said.

Idaho: There has been no electric restructuring activity in Idaho since December 1999 when a legislative study committee filed a report recommending that no legislative action be taken to encourage restructuring.

Illinois: Electric utility restructuring continues in Illinois without noticeable problems. Recently the city of Chicago and 44 suburbs announce they will pull the plug on Commonwealth Edison if one of the 13 alternative suppliers licensed in Illinois can offer them a better deal on electricity for municipal services over the next three years.

"We have agreed to combine our purchasing power and buy electricity in bulk from a single provider so that we can achieve economics of scale and reduce our operating costs substantially," said Chicago Mayor Richard M. Daley. The Local Government Power Alliance has issued a request for services (PRS) to the 13 licensed power providers in Illinois.

The government entities use about 400 MW per year, with the city of Chicago consuming about 200 MW and the Chicago Transit Authority using about 100 MW. This is the first opportunity these entities have had to purchase power competitively since Illinois deregulated electricity in 1997.

A contract award is expected to take effect next year and to last at least three years. It will involve only electricity purchased by government, not residential or commercial customers.

In order to qualify, an alternative retail service provider must lower costs for each member in the Alliance by the same percentage amount and then guarantee these savings, explained Steve Walter, Head of the city of Chicago's energy division. The RFS sent to the 13 alternative providers was deliberately silent on any required savings figure in order to encourage competition among the bidders.

Out of the 65 municipal responses the Alliance received when the aggregation idea was first proposed, 44 decided to stay after a requirement was imposed that each had to pass a city ordinance allowing the Alliance to negotiate on its behalf. The city of Chicago, Chicago Transit Authority, Chicago Park District and Chicago City Colleges – all part of the original Alliance – bring the total to 48. All committed to accept whatever the Alliance decided.

Under terms of the FRS, the winning supplier must, at the end of each month, examine each customer's bill, comparing what it would have been had the customers stayed with ComEd to what it actually is from the new provider. If the savings fall below the specified contract amount, the alternative provider has to make up the difference; conversely, he retains any excess. This arrangement eliminates any of the participating municipalities from experiencing only marginal savings or, worse still, having to subsidize other cities in the Alliance.

Bidders are being encouraged to pick and choose among the various supply options in meeting each city's energy needs. These include contracts with the supplier, other ComEd tariffs and the "power purchase option" that under Illinois' restructuring law offers customers unbundled service from the utility at market-based power and energy prices.

Under the power purchase option, customers pay transition charges since only utilities imposing transition costs are required to offer this option. A city that has numerous municipal buildings could, therefore, wind up with some facilities on each of these different pricing mechanisms.

The RFS also requires alternative suppliers to generate 80 MW, or 20%, from renewable resources. In addition, the supplier must submit plans to reduce pollution caused by the power generated. The U.S. Department of Energy will help the local governments evaluate the renewable energy proposals.

Despite these requirements, the Alliance is optimistic that with 400 MW up for bid, and 70% load factor, alternative providers will compete enthusiastically for the its business.

Responses are due October 11. Alliance is hoping that negotiations can be completed in the fourth quarter, with service beginning January 1, 2002.

Indiana: January 10, 2000, Senator Morris Mills introduced an electric industry restructuring bill (S.B. 450) that was referred to the Committee of Commerce and Consumer Affairs. The bill never made it out of committee.

Iowa: Organized labor, backed by a broad-based coalition of environmental and consumer groups, defeated electric industry restructuring legislation in Iowa in the spring of 2000. MidAmerican Energy and Alliant Energy, the two key proponents of House Bill 2530, lobbied for months to pass the legislation but could not overcome the perception that it was a utility crafted bill to benefit the utility. In the end, House Majority Leader Chris Rants, realizing he lacked the votes to pass the bill, refused to bring it forward.

HB 2530 offered retail choice to all customer classes by October 1, 2002. Those who chose to retain bundled service could do so through December 31, 2008 if they used 75,000 kWh or less annually. Rates for this service were to be frozen at current levels until January 1,2003. On January 1, 2006, the generation components of all standard offer service rates would be adjusted to market levels.

The bill enabled electric companies to recover a portion of their transition costs over the period October 1, 2002 through October 1, 2006. Eighty percent would be eligible for recovery in 2002, 70% in 2003, 60% in 2004, and 50% in 2005. The legislation also permitted electric companies to issue up to $400 million in transitional funding securities.

The IBEW's State Conference, fearing that deregulation would result in a reduction of line workers as electric companies downsized their regulated transmission and distribution system workforce in order to concentrate on the more profitable generation side of the business, sought protections in the law.

But beyond labor's effort to protect its workers was the cohesiveness of the coalition to safeguard consumer interests at large. The coalition, Responsible Electric Deregulation for Iowa (REDI), consists of 23 environmental and consumer groups, including AARP, American Wind Energy Assn., Iowa Environmental Council, Iowa Renewable Energy Assn., League of Women Voters and the Union of Concerned Scientists. It represented 750,000 of the state's 2.8 million citizens.

Legislators ignored MidAmerican's promise to build two new generating plants in Iowa if HB 2530 was passed. In the last few days of the legislative session, the utility proposed to spend up to $285 million to construct a 350 MW peaking plant and a 225 MW combined-cycle unit by 2005.

But electric rates appeared to have been the larger issue, and organized labor, the Iowa Office of Consumer Advocate (OCA) and other stakeholders lobbied hard on this point, characterizing Iowa as a "low-cost" state that could only be harmed by restructuring.

The latest of numerous studies by the OCA indicated that rates under deregulation would increase by $197 million for MidAmerican and Alliant Energy, said Gary Stewart, head of the office.

MidAmerican's President, Ron Stepien said that while electric prices over time will increase, even with customer choice, the increases would be less under deregulation. But opponents were more successful in convincing consumers that electricity prices would rise.

Because adjournment of the Iowa General Assembly ends the two-year 78th session, HB 2530 dies and new legislation must be drafted and introduced next year.

Kansas: The legislative task force studying retail electricity competition has lapsed. Legislation to extend the life of the Retail Wheeling Task Force lapsed after legislators decided not to pursue retail electricity competition issues. There are now no interim restructuring study committees in Kansas. The assessment and taxation committee is expected to devote one day this year to a discussion of the tax implications of restructuring. A utility official observed that there seem to be no demand for change in the structure of electricity markets in Kansas at this time.

Kentucky: A special Kentucky Electricity Restructuring Task Force recommended that lawmakers wait until the 2002 General Assembly to consider opening the state's electric industry to competition.

"There is no compelling reason at this time for Kentucky to move quickly to restructure," the 20-member task force concluded in its report. The task force was established during the 1998 legislative session after a deregulation bill died in committee.

A final report was presented to Kentucky Governor Paul Patton before the legislature convened in January 2000. The General Assembly meets every two years in regular session in Kentucky.

The task force said in the report that Kentucky, which relies heavily on coal-fired generation, "is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains."

Despite the possibility of congressional legislation to mandate restructuring and actions taken by 23 states to restructure, there are "obvious advantages for Kentucky adopting a wait-and-see approach to electricity restructuring," the task force said.

Such a position allows Kentucky to monitor the progress of restructuring in other states and to develop options that protect Kentucky's low rates for electricity, the task force added.

The task force also found:

- Restructuring can be expected to have multiple effects on Kentucky's electricity prices. If the state's electric rates are deregulated, price fluctuations probably would be larger in magnitude than fluctuations under cost-of-service regulation.
- Three utilities that operate in Kentucky – Cinergy, Big Rivers and the Tennessee Valley Authority – collectively have potential stranded costs that range from $295 million to more than $1 billion. The state's remaining utilities are in a "negative stranded cost" position, meaning the market value of their generating assets and purchase power contracts is higher than the book value for these assets in a regulated market.
- Restructuring is not expected to reduce the importance of natural gas in new generating capacity in Kentucky. During the past 10 years, all new capacity in Kentucky has been gas-fired. The last coal-fired unit, Louisville Gas & Electric's 495 MW Trimble County plant came on-line during the early 1990s. "As the cost advantage for gas-fired generation continues to increase and the demand for electricity continues to grow during summer peaking months, the expectation is that new capacity will be gas-fired combustion turbines."
- The task force report disappointed Cinergy, perhaps the leading advocate of restructuring in Kentucky. Cinergy is the parent company of Union Light, Heat & power, which serves about 120,000 electric customers in northern Kentucky. It also is the parent company of Cincinnati Gas & Electric and PSI Energy.

Louisiana: The Louisiana Public Service Commission has ordered its staff to move ahead with studies and hearings on restructuring issues and draw up a complete restructuring plan for the state by January 1, 2001.

But the PSC refused to take any vote at its meeting on whether restructuring was in the public interest, saying it would make that decision once it reviewed the final plan.

It also did not propose a date for the actual start of retail competition but members said that once a decision was made they might support a pilot project starting in early 2001 and implementation of full choice later that year.

The commission members said they believe Louisiana should be ready with a deregulation plan because of moves by other states in the region towards decontrol. They wanted Louisiana to stay in line with neighboring states and not begin choice ahead of them.

Both Texas and Arkansas legislatures are now considering bills, which would start retail choice in their states in 2002. Mississippi is working on a similar plan.

Unlike the other states, the Louisiana PSC has the power to order deregulation without new legislation. Therefore once it makes a decision, implementation could proceed quickly. Currently there is no proposal on restructuring before the Louisiana legislature.

The PSC staff had reported to the commission that retail choice would not be in the public interest in Louisiana at this time, but also submitted a draft-restructuring plan.

Staff is expected to submit a schedule for hearings in April covering several technical areas including stranded costs, transmission, regional impacts of decontrol and market power.

Maine: During the spring 2000 the Maine Public Utilities Commission has approved standard offer rates for Central Maine Power and Bangor Hydro customers.

Standard offer rates Bangor Hydro customers will average 4.5 cents/kWh for residential and 4.9 cents/kWh for both medium and large industrial and commercial users.

The PUC also approved a contract with an unidentified seller, which will cover most of Bangor Hydro's standard offer needs for one year starting March 1, 2000, when deregulation begins in the state. Remaining standard offer demand will be covered by spot purchases, company officials said.

In all cases the standard offer rates for residential users are lower than for business customers and because of the low rates, no competitive suppliers have registered with the state to sell to residential users at this time. This means all residential users will start with the standard offer and the only competition will be for larger loads where several power sellers and aggregators are registered.

Under the final decision, the standard offer energy rate for Bangor Hydro residential users will be a flat 4.5 cents/kWh; rates for medium sized commercial and industrial users are seasonally differentiated at 4.624 cents/kWh non-summer and 5.704 cents/kWh for summer. For large commercial and industrial users, rates are seasonally and time differentiated ranging from 3.848 cents/kWh non-summer, off-peak to 7.459 cents/kWh summer, on-peak.

The PUC also approved overall service rates, which include the standard offer, for Bangor Hydro's users in the 14 cents/kWh range. Bangor Hydro officials said small and medium users who take the standard offer will save about 3% over current regulated rates but large users will not get savings unless they but lower cost competitive energy suppliers.

The Maine Public Utilities Commission reversed a previous position, agreeing to increase the standard offer energy rates for Central Maine Power commercial and industrial users to an average 5.9 cents/kWh for medium-sized and 5.2 cents/kWh for large sized customers.

Earlier, the PUC had rejected as too high all standard offer bids from suppliers for CMP's commercial and industrial sector and at the same time it selected Energy Atlantic to supply CMP's residential standard offer users at a rate of 4.1 cents/kWh.

At the same time it set the energy price for the CMP business users at the same 4.1 cents/kWh rate and told CMP to find energy supplies on the market for the commercial and business standard offer.

The PUC said that if the cost of the energy was higher than 4.1 cents/kWh, CMP would have to treat the cost differential as a stranded investment cost and defer recovery to a later date.

In mid-January, CMP said it had found a supplier for the commercial and industrial standard offer energy but at rates well above 4.1 cents/kWh. However it proposed that the PUC increase the fixed standard offer rate to the higher market level instead of using the lower rate and requiring the cost deferrals.

In the end, the PUC agreed with this approach saying that it was better than creating large undercollections, which would have to be made up later. It also approved a contract for CMP to buy standard offer supplies from a seller covering all the commercial and industrial demand at the higher price.

In a statement, CMP officials said that because of the higher rates, customers who use the new commercial and industrial standard offer energy would get little savings compared to current prices when retail choice starts March 1, 2000.

But they predicted that the higher rates should also attract more competitive energy sellers to the state and the CMP commercial and industrial customers should be able to get lower rates by switching from the standard offer to other suppliers.

Maryland: On July 1, 2000, Maryland deregulated its electricity market, and started competition, though a suit is keeping Baltimore Gas & Electric's market closed for now. In the transition, BGE and Allegheny Energy are also shifting utility power plants to unregulated affiliates, to sell into the open market.

The state's four investor-owned utilities – Allegheny (operating as Potomac Edison), BGE, Conectiv and Potomac Electric Power – are restructuring according to settlements that they signed with intervenors last year, and which were approved by the Public Service Commission. But BGE's settlement was challenged by the Mid-Atlantic Power Supply Association (MAPSA) – a group of independent generators and marketers – which said the company's settlement sets shopping credits too low.

Those rates, which outside suppliers compete against, will start at 3.8 cents/kWh for industrials and 4.3 cents/kWh for residential users. MAPSA argues the rates are too low to allow real competition. It proposed credits ranging from 4.48 cents/kWh to 5.74 cents/kWh.

MAPSA's appeal was rejected by two courts, but it finally won a stay on June 30, 2000, from the Maryland Court of Appeals, the state's highest court. BGE sought an emergency motion to lift the stay while the issues were addressed, but the court denied the motion and set a hearing for July 20. Retail competition for BGE cannot begin before then, but the stay does not affect other utilities.

BGE lashed out at MAPSA, calling it a "group of principally out-of-state power suppliers," noting that the settlement was signed by consumer advocates, commercial and industrial user groups, the PSC staff and a number of marketers. BGE said MAPSA's proposed rise in shopping credits would also hike the "standard offer" rates that BGE will charge users who stay with the utility service, making service more expensive, and driving more customers to outside suppliers. The stay will also delay a 6.5% rate cut that was part of the settlement.

The stay, however, does not prevent BGE's parent, Constellation Energy Group (CEG), from transferring its utility plants to unregulated subsidiaries. It will deregulate 6,200 MW of plants, including 4,500 MW of fossil fuel and hydro units and the 1,700 MW Calvert Cliffs nuclear station, whose two units were recently re-licensed until 2034 and 2036. The fossil fuel and hydro plants will go to a new unit called Constellation Power Source Generation and Calvert Cliffs to Constellation Nuclear. Power from these merchant units will be sold in the wholesale merchant market by Constellation Power Source.

At the same time, CEG is consolidating the ex-BGE fossil and hydro plants with its existing portfolio of independent power projects, which have been developed or acquired by Constellation Power since 1985.

That includes 1,841 MW of equity in 28 projects in operation or under construction, plus 3,850 MW of merchant plants in development across the country.

According to CEG, these moves are part of an intensified focus on the North American wholesale merchant market. Chief executive officer Christian Poindexter said that by 2001, the company expects to see roughly two-thirds of its earnings coming from the unregulated, competitive businesses, with the balance coming from utility BGE.

The wholesale marketing unit, Constellation Power Source, is also involved in a joint venture with Goldman, Sachs & Co., called Orion Power Holdings. That company was established to acquire divested assets and it has purchased 79 fossil and hydro plants, totaling 5,227 MW, from Consolidated Edison, Niagara Mohawk Power, Duquesne Light and PG&E Generating.

Maryland's deregulation has also allowed Allegheny Energy to transfer 1,200 MW of capacity to its unregulated generation and marketing unit, Allegheny Energy Supply. Previously it shifted 3,700 MW of Pennsylvania capacity to the supply company and will transfer more capacity as deregulation hit other states in which its utilities operate. The company also has a goal of 10,000 MW in merchant capacity, including new power plants in development.

Potomac Electric Power is divesting its capacity to focus on distribution and services, and recently agreed to sell 5,100 MW of plants in Maryland and Virginia to Southern Energy Inc.

Conectiv has agreed to sell its baseload fossil plants to NRG Energy and its nuclear holdings to PECO Energy and PSEG Power, but it is retaining its peakers and mid-peak plants to market special packages of power and ancillary services.

With retail competition underway in the state, the Maryland Public Service Commission has recently ruled that unregulated affiliates of utilities must pay royalties to ratepayers if they use the company name of logo. The PSC is also preventing affiliates from sharing certain employees with their utility sister companies (Order No. 76292).

In response, Potomac Electric Power is challenging the order in state court. The company, which operates retail energy and telecommunications units, complains that the new rules do not apply to out-of-state utilities, whose affiliates will gain an advantage in the Maryland market. Other Maryland utilities also condemned the PSC rules, and some are considering suing as well.

Under the new rules, if a utility permits an affiliate to use its name and logo, it must "impute a royalty to the regulated gas and electric utilities: 1) for the value of the name and logo of the utility; and 2) for the unqualified benefits conferred upon affiliates because of lack of complete separation." The PSC did not establish the amount of royalties, but plans to open a separate proceeding for this purpose.

Some marketers wanted the PSC to ban affiliates' use of utility brands altogether, saying they would allow the companies to capture greater market share than they would gain based purely on products and prices. In response, utilities pointed out that names and logos are utility assets that have never been included in rate base. Therefore, they argued, ratepayers are not entitled to anything because these assets have never provided revenue through the rate of return. Further, utilities said than any "goodwill" or other intangible benefits associated with brand names have been accumulated through good management and service.

The PSC refused to ban affiliates' use of names and logos, but it determined that "some compensation is due to the utilities and indirectly to the ratepayers, for the affiliate's use of the assets, which value was built at ratepayers' expanse." It added, "Not only does the name/logo have value that must be recognized, but the 'transfer' of this asset to an affiliate is anti-competitive because no other company would be permitted to use the asset without compensating the utility."

Another part of the PSC order affects sharing of employees. The PSC ruled that utilities and affiliates may share "general corporate services employees" because affiliate contributions toward salaries can reduce the cost of service for ratepayers. However, they may not share "utility operational and managerial employees," such as lawyers, accountants, account executives and customer service representatives, as well as, employees in market research, public relations and advertising.

On July 24, 2000, Pepco filed suit in Maryland Circuit Court, seeking a "stay" of the PSC order. It said the PSC rules would cause "irreparable harm," particularly since utility affiliates from other states would not be subject to the restrictions.

Massachusetts: Massachusetts utilities will no longer be forced to charge below market prices for default service and have been directed to base these rates on wholesale bid prices beginning January 1, 2002.

The Massachusetts Dept. of Telecommunications and Energy issued the ruling June 30, 2000 after months of controversy. Utilities had complained to regulators that they could not procure wholesale power below the 3.8 cents/kWh to 4.5 cents/kWh they are required to charge, and, as a result, were losing money on the growing number of default service customers.

The ruling calls for utilities to begin issuing competitive bids seeking six-month to one-year contracts. After selecting suppliers, utilities will pass on contract costs to default service customers, who now number 527,000 in Massachusetts. The service is available to those who have left their competitive supplier or who are new to a service territory.

Default service customers will be offered two separate retail pricing options: one fixed and the other variable. Residential and small commercial and industrial customers who are on the service will automatically be charged a six-month fixed price, with the option of switching to a variable monthly rate plan. Conversely, medium and large C&I customers on the service will automatically be charge variable monthly rates, with the option of switching to six-month fixed rates.

In settling the contract length, the DTE said it tried to create a balance between fostering the retail market and keeping prices low. Longer contracts may bring in lower prices for consumers, but they poorly reflect the true wholesale market and could hinder development of a robust retail market if they are too low. The six-month to one-year time frame strikes a "reasonable balance" between the competing interests, the DTE said.

Utilities must seek separate bids for residential, commercial and industrial customers. But the DTE has yet to decide if it will allow utilities to set up different rates for each class. The agency said it will evaluate the bids and decide if they indicate that differentiating rate by class make economic sense.

The ruling prohibits utilities from passing on any administrative costs associated with the service. Retail marketers had pushed for the cost to be passed on, but the DTE said they were not large enough to justify the burden of calculating them.

The DTE also rejected recommendations that it create a uniform statewide request for proposals, saying utilities will need flexibility to get best prices.

The Massachusetts decision does not impact utility standard offer customers, which account for most customers in the state – about 2 million. SO service is for those who have yet to venture into the competitive market and remains priced at 3.8 to 4.5 cents/kWh. The utilities have locked in long-term power purchase contracts to supply this standard offer power and are not subject to the same market fluctuations that default service has seen.

The number of customers buying from retail suppliers remains small, with only about 7,000 reported in recent figures released by the state Division of Energy Resources.

Michigan: After years of wrangling and numerous failed attempts, the Michigan Legislature finally passed an electric utility restructuring package which retains the numerous customer choice orders promulgated by the Michigan Public Service Commission over the past several years.

The bill grants all customers the right to select their electric suppliers by January 1, 2002, and gives to residential customers a 5% rate cut for at least three years.

The legislative package (Senate Bill 937), with companion bills dealing with securitization and municipal utilities) was signed into law by Michigan Governor John Engler on June 3, 2000. The final version of the multi-bill package, deleted controversial language that prohibited non-utility affiliates who built merchant plants from selling the output directly to retail customers. Now, a merchant plant making sales to retail customers is considered an alternative electric supplier and must obtain a license under Michigan law.

The final version treats alternative suppliers as electric utilities in so far as they are required to secure franchise agreements in the municipalities and townships in which they plan to do business. In the final version, however, aggregators for schools are exempted from the franchise requirement, thus creating a breach between these aggregators and other power marketers.

A new stand-alone bill, SB 1256, was passed by the Senate on June 1 in an attempt to address this breach. It revises the law so that marketers who are not otherwise acting as electric utilities "tearing up roads to build new rights-of-way, for example" are not treated as utilities and do not, therefore, have to secure municipal franchises. The bill is currently before the House Energy and Technology Committee.

Minnesota: In January 1999, the Legislative Electric Energy Task Force advised the legislature to wait and learn from the restructuring going on in other states. In May, the state Public Utilities Commission ordered its staff to develop a comprehensive electricity and gas deregulation proposal. The PUC wants to present a comprehensive gas and electric utility restructuring proposal to the 2001 legislature.

Mississippi: The Mississippi Public Service Commission has ruled that it is not in the public interest to begin retail competition in the state at this time. May 2, 2000, PSC Chairman Nielsen Cochran said the commission had determined that because Mississippi was a low-cost state, deregulation would cut costs for some large users, but probably not for all users and that there was evidence some users might face higher total costs because of retail competition.

Also, because of the strong position of local utilities, Cochran questioned whether competing sellers would enter the state once the market was opened. If they didn't, he noted, small users would not have meaningful choices of suppliers.

He said the PSC believed it was unlikely the federal government would force states to deregulate their electric markets, but feared federal guidelines in areas such as transmission would be forced by the Federal Energy Regulatory Commission on those states which chose to deregulate, hiking costs for users.

He said that the PSC might be able to limit adverse impacts on users from deregulation through complex transition regulations. But it was unclear from experiences in other states whether true competition could actually be achieved after the transition period. It made sense for Mississippi to wait to see how things played out in those states before acting.

The PSC, therefore, found deregulation of the state's electric market would be premature at this time. Instead, the commission will monitor national developments and review the issue again if there is new evidence deregulation would be in the interest of all the customers.

The ruling effectively cancels a PSC staff plan issued in late 1997 to start retail choice in the state in January 2001. It also appears to insure that the state legislature will take no action on the issue in the foreseeable future. A plan had been floated in the legislature to set up a committee to review electricity deregulation later this year but lawmakers said they now wanted to review the PSC findings before making any decisions.

Missouri: In 1998 a final report by the Missouri Retail Competition Task Force recommended a cautious approach to deregulation. There was no significant restructuring activity in Missouri through 1999. During the first quarter of 2000 several restructuring and customer choice bills were introduced in the Missouri Legislature. Hearings were held on H.B. 1842, H.B. 1778, H.B. 1895 and S.B. 882. All of these bills were continued but no further action has been taken since the hearings.

Montana: Montana passed restructuring legislation in 1997 and in 1998 large users and industrial customers were eligible to switch suppliers. Some 80% of Montana Power's industrial customers have since chosen other power providers.

The Montana Public Service Commission has issued rules that will allow about 250,000 of Montana Power's residential and small business customers who decline to choose new suppliers, or are ignored by suppliers, to receive power from default providers when the state fully deregulates the industry in 2002. The default supplier concept was approved in Senate Bill 406 and House Bill 211 that were passed early in 1999 by the legislature

The Commission identified three types of default suppliers; one category of default suppliers will be wholesalers who will bid into a pool in a competitive solicitation. Another will be cities, counties and consolidated governments and the last will be electricity buying cooperatives formed as default suppliers. Some 5% of the electricity from default suppliers must be generated by an approved renewable energy resource.

The PSC will determine specific default service tariffs and will have jurisdiction to license default suppliers.

Nebraska: This unusual state with a unicameral legislature and 100% public power has begun a three-year legislative study of the state's electric power industry. The goal is to examine moves towards competition in the industry nationwide and develop alternatives to enhance the ability of Nebraska's public power industry to thrive in a competitive environment. This study was completed in 1999.

January 5, 2000, Legislative Bill 901 was introduced as a follow-up to the three-year study. This bill required the Power Review Board, which regulates public power in Nebraska, to monitor certain conditions to prepare the state for retail competition, rather than tie restructuring to a "date certain" approach.

The legislation defines two new terms in Nebraska law: Regional Transmission Organizations and unbundled retail rates. The legislation empowers the Power Review Board to hold public hearings concerning the conditions that may indicate that retail competition in the electric industry would benefit Nebraska's citizens and what steps, if any, should be taken to prepare for retail competition in Nebraska's electricity market. L.B. 901 also requires the Board to submit an annual report to the Governor and the Legislature.

The governor signed the bill into law on April 11, 2000.

Nevada: Nevada's retail market fell into turmoil when Governor Kenny Guinn delayed the onset of customer choice indefinitely and – partly in response – the state's dominant utility dropped plans to create a competitive retail supplier.

Governor Guinn postponed implementation of the state's competitive power market, originally set to begin December 31, 2000, then pushed back to March 1. The first delay was at the request of industry participants concerned about possible Y2K complications. The new delay centers on the readiness of the industry and the state.

Several major issues remain unresolved. One is Sierra Pacific Resource's stranded costs, almost all of which are related to power purchase agreements with independent generators. There are also issues relating to billing and metering that must be resolved.

Another issue is the funding and operation of the Mountain West ISA, an entity with start-up costs of some $20 million or more. Sierra Pacific Resource sees Mountain West as an interim step toward a regional system administrator and the company is reluctant to provide major funding to an entity with an expected life of two to three years.

Guinn proposed hammering out resolutions to many of the issues in a secret "summit meeting" March 7, 2000, which he personally would chair. The Governor invited representatives from Nevada Power, Sierra Pacific, the state consumer advocate, PUC staff and representatives from the gaming and mining industries, the state's major commercial and industrial consumers. Excluded from the meeting, however, were the media as well as companies that intend to compete with Sierra Pacific Power and Nevada Power.

Residential consumers are largely unaffected by the delay because rates are to be capped for a three year period. Industrials will be at the table because it is they who stand to benefit most from a competitive industry and they are the targets of alternative suppliers.

To date, there has been no resolution to the restructuring issues and retail competition has not begun in Nevada. In a subsequent action, Sierra Pacific Resources filed a federal lawsuit challenging the constitutionality of the 1999 law that set deregulation in motion. At issue is the three-year rate freeze written into the law (Senate Bill 438) for operating units Nevada Power and Sierra Pacific Power. The suit claims the law is confiscatory because it does not provide a procedure to allow utilities to request rate increases under extraordinary circumstances. The suit is currently pending.

New Hampshire: Ending a three-year battle with Northeast Utilities subsidiary Public Service Co. of New Hampshire, the New Hampshire legislature on May 31, 2000 passed a law approving the utility's controversial restructuring plan.

PSNH previously announced that it was willing to accept the conditions placed on restructuring by the lawmakers and the final votes by the Senate and House of Representatives on SB 472 opened the way for retail competition to start for 420,000 customers possible as soon as October 1, 2000.

The key to the approval was a PSNH agreement to provide more upfront savings to ratepayers including a guaranteed 5% rate cut October 1, 2000 – whether or not retail competition actually begins on that date.

Under the plan, PSNH agrees to take several specific steps and absorb an estimated $450 million in stranded costs out of a total claim of $2.3 billion. This will allow it to reduce rates for customers an average 16% on the day retail choice starts, including 17.2% cut for residential users.

In return, the legislature pulled back from a provision that included in the rate calculations potential savings from the proposed merger of Northeast Utilities with Consolidated Edison. Instead, the legislature left it up to the PUC to determine what savings from the merger should be passed on to users when its reviews the deal in a separate case. However, the bill says the merger cannot be approved unless PSNH customers get a "just and reasonable" share of the savings.

The bill also provides authority for PSNH to securitize a total of $800 million in stranded costs including $670 million in costs related to its own plants and $130 million in costs to buy down expensive IPP contracts.

At the same time, PSNH must sell its 1,200 MW of fossil fuel generation capacity by July 1, 2001 and use the proceeds from the sale to help reduce its stranded costs. Until the assets are sold it can use power from the plants to help cover its standard offer energy demand. NU affiliates cannot buy them if the sale takes place after the NU-ConEd merger.

New Hampshire towns have until October 1 to decide if they want to buy PSNH hydro plants, totaling 65 MW, inside their borders. NU will also sell its 40% share of the 1,200 MW Seabrook nuclear plant in New Hampshire.

The bill also sets standard offer energy costs PSNH residential and small business users at 4.4 cents/kWh for the first 21 months after competition begins. After that the standard offer rates for small users will rise to 4.6 cents/kWh for 12 months and then the service will be terminated.

The PSNH standard offer energy charge for large commercial and industrial users will be 4.4 cents/kWh for the first 9 months after competition begins. After that, standard offer energy will be offered for another year at market rates.

PSNH will drop all pending legal challenges to restructuring, especially a federal court case filed in 1997 against an original state restructuring plan which has hamstrung state regulators ever since.

Once PSNH starts retail choice, about 85% of all users in New Hampshire will be able to buy competitive power.

New Jersey: The New Jersey Supreme Court has decided to hear a challenge to the Board of Public Utilities' securitization and restructuring orders. On April 13, a three-member panel of the Appellate Division of Superior Court of New Jersey affirmed the August 24, 1999 BPU orders, rejecting an October 1999 challenge by the New Jersey Business users, Co-Steel Raritan and the state Office of Ratepayer Advocate.

The plaintiffs appealed to the state Supreme Court, which on July 14, 2000, agreed to hear the case. On July 20, the Supreme Court scheduled November 8, 2000 oral arguments.

New Mexico: The complexities of integrating the administrative, computer and back-office functions of New Mexico's electricity utilities with those of their potential competitors prompted the state Public Regulation Commission to delay by one year the start of electricity supply competition.

The PRC changed the start date for competition to January 2002 for residential and small commercial customers of the utilities in the state – Public Service Company of New Mexico, Southwestern Public Service Co., El Paso Electric Co. and Texas New Mexico Power – and set the date for large customers to July 1, 2002.

The dates are now compatible with the dates for the start of competition in Texas. The PRC said such coordination is important because Southwestern Public Service, El Paso Electric and Texas New Mexico Power each have customers in Texas as well as New Mexico.

Each utility informed the PRC they supported the delay. However, the PRC did not alter its requirement that all regulated utilities file their completed transition plans by June 1, 2000. The transition plans will detail the costs faced by each utility as they prepare for competition.

PNM estimates its transition costs in the range of $50 million to $55 million. The utility, the largest in New Mexico with 1.3 million of the state's 1.6 million residents, said the costs reflect changes it must make in its computer and administrative operations to integrate with the systems of possible competitors.

Those costs, along with the costs incurred by other incumbent utilities in the state, will be recovered through a systems benefit charge imposed on consumers over a six-year period. All consumers – whether they switch supplier or not – will pay the charge, which will be established in the near future.

The commission said it also delayed implementation to accommodate independent administration of the transmission system by Desert Southwest Transmission and Reliability Operator (Desert STAR), the proposed independent system operator for the Southwest.

Although development of Desert STAR is progressing the current schedule would not have it in operation by January 2001. Desert STAR participants include investor-owned electric utilities, rural cooperatives and municipals in Arizona, New Mexico and Nevada, as well as, the west territory of Texas El Paso Electric.

Not all parties were pleased with the delay of competition. The New Mexico Industrial Energy Consumers, representing the state's large users, complained that postponing competition postpones energy savings.

New York: Throughout 1998 and 1999, New York utilities opened their service territory to retail competition. In the process most utilities divested their generation resources and began purchasing power through the New York Independent System Operator.

Utilities have been warning that summer 2000 could bring "disaster," since pricing in the New York Independent System Operator is already "irrational" and inflated. New York Electric & Gas recently asked the Federal Energy Regulatory Commission to suspend market pricing in New York for the summer, replacing it with cost-based energy rates.

. This is not the first hint of trouble in NYISO, which began operating late last year, taking control of the transmission grid that used to be run by the New York Power Pool. Recently, several utilities complained that reserve prices have risen alarmingly. In response NYISO temporarily capped reserve prices.

In its petition to FERC (Docket EL00-70), New York Electric & Gas asks the commission to suspend market-based rates for the period June 1- Oct. 31, or until FERC determines that the market flaws have been mitigated. In place of market rates, NYISO would use cost-based rates, determined by rate cases. The company stresses that it supports market pricing, but adds that "the confluence of severe implementation problems … have strained the NYISO market to the point to avert a potential disaster this summer."

New York Electric & Gas also points out that energy imports from outside New York "have been unworkable," and noted that severe cuts to inter-control area transactions have led the PJM Interconnection to consider discontinuing day-ahead transactions with New York.

Another problem is that NYISO software "incorrectly predicts less expensive supplies, only to force purchase at much higher prices."

At the same time, energy prices fluctuate substantially over short periods "in an inexplicable fashion," and there is a "significant lack of convergence in day-ahead and real-time energy prices." New York Electric & Gas also complains of "gaming and the exercise of market power" by a small number of generators.

North Carolina: The Study Commission on the Future of Electric Service in North Carolina issued its final recommendations to the state legislature and called for a sooner-than-expected start to retail competition. When the committee released its draft recommendations, June 30, 2006 was the recommended date for the implementation of full electric-customer choice.

The final recommendation, approved April 3, 2000, would give half of each utility's customers the right to select their supplier by January 1, 2005 and give the remaining customers choice by January 1, 2006.

The study commission called for the first round of customers to receive a "shopping credit" equivalent to the then-current competitive market price for its class of customer – residential, commercial or industrial – and for the customers to pay their incumbent supplier "an appropriate transition charge."

The panel recommended that investor-owned utilities' retail rates be frozen through December 31, 2004, to enable IOUs to pay down all or most of any stranded costs they may face. Utilities that want to could lower their rates or modify their rate design in the interim – with the North Carolina Utilities Commission's okay.

The NCUC also would hold proceedings to determine what IOU rates should be during the 2005 calendar year, and what stranded-cost-recovery charges, if any, should be charged that year.

"If any [IOU] is awarded additional stranded cost recovery after December 31, 2004, the NCUC shall initiate a one-time true-up of such utility's remaining stranded costs by July 1, 2007," the study commission said. In its draft recommendations, the panel had called for a rate freeze through June 30, 2006.

The study commission put off until 2001 a recommendation on what remains the most challenging issue of all; how to deal with the multibillion-dollar stranded costs faced by 51 municipal utilities who are members of either the North Carolina Eastern Municipal Power Agency or North Carolina Municipal Power Agency No. 1.

In recognition of muni concerns, the panel emphasized that nothing in the final recommendations it released "is intended to preclude the municipalities from being able to sell or retain their electric distribution systems by making a payment to the [muni power agency] debt equivalent to the appraised value of the distribution system."

Still other elements of the final recommendations called for a "standard offer service" with competitive rates to be offered to customers who "make the passive choice of staying with their current supplier" even after they are given the right to choose alternatives.

The panel also called for a "public benefit fund" to address low-income, renewable-energy and energy-efficiency issues that may not be met in a deregulated market; and for a requirement for energy suppliers to include at least a small percentage of renewable electricity in the power they sell.

Finally, the study commission said that by July 31, 2002, the NCUC should report to it about the intended structure of a regional transmission entity, and the North Carolina Dept. of Revenue should report to it about tax-law changes needed with the introduction of retail wheeling.

Legislators are expected to only review the study commission's recommendations in their 2000 "short session," which begins in May. Legislation to implement retail wheeling is likely to be voted on – and approved – during the longer legislative session in 2001.

North Dakota: Changes in the state's service territory law were defeated during the 1999 legislative session. A standing six-year legislative committee examining competition in the electricity industry is due to file a report during the legislature's next regularly scheduled session in 2001.

Ohio: The Public Utilities Commission of Ohio (PUCO) approved a stipulation in the FirstEnergy Corp. electric transition case which creates an opportunity to begin a competitive retail electric market in Ohio and provide opportunities for consumers to begin saving on their electric bills beginning January 1, 2001.

"There has likely never been a settlement in a major case before this Commission in which the overwhelming majority of intervenors either supported or did not oppose the resolution of issues presented by the stipulation. As a package, it advances the public interest by resolving the extensive and complex issues raised in this proceeding without incurring the extensive time and expense of litigation that would otherwise have been required," states the Commission order. Under the terms of the stipulation approved today by PUCO, FirstEnergy agrees to:

1) Offer at least 20 percent (1,120 megawatts) of their tariff generation capacity to independent marketers, brokers and aggregators at fixed prices for resale to end users.
2) Provide end dates of customer payments for transition costs of December 31, 2006 for Ohio Edison, June 30, 2007 for Toledo Edison and December 31, 2008 for Cleveland Electric Illuminating;
3) Not increase distribution rates through December 31, 2007;
4) Continue residential bill credits of $1.50 per month for OE, and $5 per month for TE and CEI residential customers;
5) Create and maintain a technical task force designed to address and attempt to resolve technical and operational issues involving the companies that may arise following the beginning of customer choice;
6) Continue to support low income housing energy efficiency improvements, with grants totaling $5 million per year through December 31, 2005. The available grants total $2 million per year each for OE and CEI, and $1 million per year for TE.
7) Forego recovery of up to $500 million in transition costs if the 20 percent customer shopping rate is not met by the end of the market development period. Ohio law establishes a 20 percent benchmark for customer shopping rates; and
8) Reimburse marketers for certain transmission costs.

On June 22, 1999, the Ohio General Assembly passed legislation requiring the restructuring of the electric utility industry and providing for retail competition with regard to the generation component of electric service (Am. Sub. S.B. 3 of the 123rd General Assembly). Governor Bob Taft signed this legislation on July 6, 1999 and most provisions of S.B. 3 became effective on October 5, 1999 requiring each electric utility to file with the PUCO a transition plan for the company's provision of retail electric service in Ohio.

On December 22, 1999, FirstEnergy Corp., on behalf of its Ohio operating companies (Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company) filed its transition plan with PUCO. The companies serve 2.2 million Ohio and Pennsylvania electric customers.

On April 17, 2000 a stipulation was filed on behalf of FirstEnergy, the PUCO Staff, the Ohio Consumers' Counsel, Industrial Energy User-Ohio, Kroger Company, AK Steel, the Ohio Council of Retail Merchants, Shell Energy Services Company, Astabula County Community Action Agency, Corporation for Ohio Appalachian Development, Neighborhood Housing of Toledo, the Ohio Hospital Association, the Cleveland Housing Network, and Consumers League of Ohio. The Ohio Manufacturers Association and the Greater Cleveland Growth Association also subsequently signed the stipulation. On May 9, a second agreement was filed at PUCO by FirstEnergy, NewEnergy Midwest, LLC, WPS Energy Services, Inc., and Columbia Energy Services Corporation, and Columbia Energy Powers Marketing. The Mid-Atlantic Power Supply Association, Strategic Energy, LLC, Exelon Energy, National Energy Marketers Association, Unicom Energy, Inc., and Enron Energy Services, Inc. signed the agreement as non-opposing stipulation parties.

Evidentiary hearings in this case were held on May 10-12, and 15. Local public hearings were conducted on May 30 in Toledo, June 2 in Cleveland, and June 5 in Barberton.

Stipulation agreements have also been filed by American Electric Power, Cinergy and Dayton Power & Light. The PUC expects to rule on the individual agreements by late October.

Oklahoma: Efforts to pass implementation guidelines for electric restructuring in Oklahoma fell apart in the closing hours of the legislative session, leaving the state with a July 1, 2002, deadline for deregulation with no road map to get there.

The final version of the implementation measure sailed through the Senate on May 23, 2000. With mounting opposition, it was returned to the Senate on May 25 to add language sought by Attorney General Drew Edmondson. It added a study to be done in 2004 to ensure that competition was taking hold and, if there was a finding that it was not, what kind of mitigation plan might be appropriate.

While Edmondson wrote a letter of support for the bill, it was not enough to stop vocal critics, who fell into three camps; industrial consumers, who felt they were not getting enough from the bill; consumer advocates led by Oklahoma Corporation Commissioner Denise Bode, who felt the measure was weak on consumer protection; and political purists led by Governor Frank Keating, who objected to having such a complex piece of legislation considered in the legislature's closing hours.

Oklahoma's constitution mandates that the legislature adjourn for the year at 5 p.m. on the last Friday of May. The bill went to the House floor shortly before the deadline and failed. The Electric Deregulation Task Force, created by earlier laws that set the deadline for deregulation, remains in operation until January 1, 2003, and could provide a vehicle to continue work on deregulation.

Oregon: Oregon's efforts to grant open access to large electricity customers may be jeopardized due to Bonneville Power Administration rules for allocating power to residential users.

Under Oregon's restructuring legislation, large commercial and industrial customers will be granted direct access beginning October 1, 2002, and small commercial and residential customers will remain with their utilities. The legislation, which seeks to ensure that residential customers of investor-owned utilities are not harmed by restructuring, says that residential customers who now receive low-cost BPA power through their utilities should continue to receive that power.

But the Federal Power Act, which determines how the BPA allocates power, says the amount of power BPA provides to investor-owned utilities and their residential customers is a function of a utility's "net requirements." If a utility loses some of its load as a result of restructuring or other factors, then BPA reduces the amount of power available to that utility for its residential customers.

The OPUC and others have proposed a number of changes to the Federal Power Act, but the BPA and public utilities are resisting changing legislation.

Alternatively, after opposing restructuring in Oregon for several months, PacifiCorp has filed a compromise proposal with the Oregon Public Utility Commission for implementing Oregon's restructuring law. The compromise, filed June 12, 2000, calls for a new provision designed to shield large commercial and industrial customers from price increases.

PacifiCorp initially opposed restructuring because the company didn't think any customers should be forced to purchase on the open market and bear the risks of that market. Under the compromise proposal, the OPUC may change the existing definition of "large nonresidential" customer, not defined as customers who purchase 30 kW or above, if the OPUC determines the change is in the public interest. The OPUC would change the definition if it found that large nonresidential customers would pay more under open-access or the standard offer than they would if they stayed with a utility under traditional rates, according to the proposal. Any effort to change the definition would be formally completed by March 1, 2002, according to the proposal.

PacifiCorp's proposal also allows the company to dedicate a fixed slice of its generating resources to Oregon customers. Right now, generating resources are allocated to PacifiCorp's customers in different states based on what the customers contribute to peak demand, making it difficult to allocate a given slice of total resources permanently to Oregon customers.

The OPUC is expected to issue an order in early summer.

Pennsylvania: The Pennsylvania Public Utility Commission will allow utilities to charge market rates to big customers that jump back to utility service from competitive suppliers (Docket No. M-00960890F0017).

As summer approached and market prices rose, the PUC grew alarmed when it saw many commercial and industrial (C&I) users switching from competitive suppliers to their utilities to avoid high summer rates from marketers. They were able to save money this way because rates for utility "default" service – also called "provider of last resort" (PLR) service – are capped under the state's restructuring law. This was meant to protect consumers, but the PUC feared that the big users were "gaming" the system. Duquesne Light told the PUC that about 525 MW out of 830 MW of load served by marketers prior to May 1, 2000 has returned to PLR service for this summer.

Utilities complained that they are forced to buy expensive summer power to serve these customers – particularly utilities that have divested their capacity. The commission sympathized, but at the same time, it grew uneasy at the response that some utilities adopted, which was requiring returning C&I customers to stay with utility service for 12 months. The PUC felt that this unnecessarily restricts their options in the competitive market.

As a compromise, the PUC suggested letting C&I customers return for 60 days, during which time they could seek new suppliers, but would be charged market-based rates by the utilities. It sought comments and received a favorable response, since this approach affords the utility an opportunity to recover expensive supply costs, while offering the C&I customers an alternative to staying with the utility for a 12-month period.

The PUC has now ordered utilities that already have 12-month "stay-in" requirements to file plans for the market rate alternative. It also urged other utilities to file plans covering both options. The commission stressed that it does not want to impose a single plan on all utilities, but is offering guidelines for their filings. It suggested that C&I users that returned in May should get 120 days (from the time of their switch) to find a new supplier, while those who switched between June 1 and September 1, should get 90 days. After that, 60 days will be sufficient, it said.

Rhode Island: The Rhode Island Public Utilities Commission voted to hike Narragansett Electric's standard offer rates to ward off a projected $27 million shortfall caused by rising wholesale prices.

The increase, from 3.8 cents/kWh to 4.1 cents/kWh, comes on the heals of a similar rate hike in "last resort" rates approved earlier. Standard offers, the service taken by most customers, is for those who have yet to enter the competitive market. Last resort service is for customers who enter the competitive market, but decided to return to utility service.

Narragansett Electric, a subsidiary of National Grid USA, and the only major utility in the state, requested the increase in SO rates after its wholesale suppliers increased their prices. Under a contract the utility has with suppliers through 2009, the suppliers can pass on fuel cost increases when they reach a certain trigger point. Although SO service has been available for more than two years, this was the first time the fuel prices rose enough to trigger the increase.

Aside from possible fuel price increases, SO prices are set over the life of the contract to gradually increase each year, culminating at 7.1 cents/kWh in 2009. The wholesale suppliers for Narragansett Electric's SO service are PG&E National Energy Group, Constellation Power Source, NRG Energy Marketing and TransCanada Power Marketing.

The new SO rate takes effect July 1, 2000, but it is not clear how long it will continue. The PUC told the utility to monitor fuel prices and issue regular reports, possibly every 60 to 90 days. Based on the regular reports, the PUC may raise or lower SO rates.

The PUC acknowledged that this approach is cumbersome, so it plans to solicit comments from interested parties on other ways it might deal with fuel price changes, according to Lindsey Johnson, special counsel to the PUC. No schedule has been set yet for accepting comments.

The Energy Council of Rhode Island, which represents large users, did not oppose the SO rate increase, but has challenged an increase in last resort rates that was approved earlier. TEC-RI has filed with the state supreme court arguing that the rate hike was too abrupt, giving members no time to find alternative suppliers for the summer.

South Carolina: Senator Verne Smith introduced legislation February 23, 2000 that will deregulate South Carolina's electric industry and guarantees all South Carolinians the right to choose their electric provider.

"Electric deregulation is coming to South Carolina -- it is inevitable," said Sen. Smith upon introducing the bill. "As we move forward and consider how to restructure our electric industry we must keep the people of South Carolina foremost on our minds. I believe we can offer customer choice in a way that will allow every customer an opportunity to benefit from electric deregulation. Furthermore, I believe Senate Bill 1168 provides the framework to do just that.

"Hopefully, the Senate Task Force on Electric Deregulation can use this bill as a vehicle in their deliberations. I look forward to working with Senator Tommy Moore to make sure that our citizens are not losers in this deregulation battle to come and that municipal power systems have an opportunity to compete in a deregulated electric market" Sen. Smith continued.

Major provisions of Senate Bill 1168 include:

1. All customers, including residential, business and industrial, regardless of size or location, will be allowed a choice of electric suppliers.
2. The Public Service Commission (PSC) must certify all companies wishing to sell electricity in South Carolina.
3. A statewide customer education program will be conducted, lead by the PSC, which would provide customers with a framework to understand the changes in the electric market and to evaluate the benefits of service options.
4. Generation and distribution services will be provided by separate entities.
5. Verifiable stranded costs, associated with the construction of generation facilities, will be recovered during a period not to exceed ten years. Stranded cost recovery will be overseen by the PSC and will be recovered through a non-by-passable charge to the customer. Stranded cost will be calculated and recovered for each generation facility. In the case of the Catawba Nuclear Plant (jointly owned by Piedmont Power, Saluda River Electric Cooperative and Duke Energy), stranded costs will be calculated for all three utilities and recovered from the customer base of all three utilities.
6. Three years after passage of the bill, all customers will be allowed a choice of electric provider.

The S.C. Legislature has studied electric deregulation for several years. In 1998, a task force was created by Senator Donald Holland and Chaired by Senator Moore. The task force, comprised of senators, and utility, industry and customer representatives, has announced plans to hold a series of public hearings on deregulation across the state in early 2000.

There has been no further action on either Senate Bill 1168 or House Bill 3902.

South Dakota: There has been no electric industry restructuring activity in South Dakota.

Tennessee: The Tennessee comptroller, in a report written for the state legislature says Tennessee should begin preparations for electricity deregulation even though it is not clear how deregulation will occur in the Tennessee Valley Authority-dominated state.

According to the report by Comptroller John Morgan, if Tennessee took no preparatory measures and ultimately remained a "non-competing island in a sea of competitive states" electricity consumers, providers and state and local government would be hurt.

The report was requested in 1998 by the Joint Study Committee on Electric Utility Deregulation. The committee has held several hearings on the issue in the last two years, but so far no legislation has been proposed.

It has been widely assumed that because virtually all utilities in the state are customers of TVA, and thus exempt from state regulation, that Tennessee lawmakers will wait and see whether Congress passes a bill covering retail competition in the TVA areas.

In his report, the comptroller said the legislature may eventually have to consider several taxation, regulatory, public education and environmental issues.

The report said a key deregulation issue will be TVA's stranded costs and debt and how that would impact consumer bills. It noted that because of its $27 billion debt, TVA was at a "considerable [financial] disadvantage" compared to other utilities. It also said that under deregulation TVA residential users could lose access to low cost preference power, which now keeps their rates low.

Tennessee would also want to change its tax structure, going to some form of electricity consumption tax which would be as close to the consumer as possible and dropping the current gross receipts tax, the study notes.

The comptroller also said the Tennessee Regulatory Authority, which now has little role in electricity regulation, should be given major responsibilities over power sellers and utility distribution operations if retail competition was adopted.

The report argues that the legislature should also consider rules to unbundle generation, transmission and distribution in the state to prevent market abuses and consider an independent system operator or some other form of grid company to maintain open access and reliability.

Texas: The Texas Public Utility Commission continues through a process of proposals, comments and workshops to develop the rules necessary to start retail competition, January 1, 2002.

In June, interested parties were invited to comment on newly proposed rules for Texas's retail electric pilot, which will begin on June 1, 2001 and will open 5% of each utility's total electrical load to competition.

The proposed rules, which the Texas Public Utility Commission published on June 16, 2000, had been under development since March, when the PUC for the first time decided to use the "negotiated rulemaking procedures" allowed under Texas law.

Under this approach, representatives of a variety of stakeholder groups named to a negotiating committee met once a week from early March through early May in an effort to reach a consensus. They largely succeeded.

Among other things, the committee agreed on proposed rules that call for customer participation within each utility service territory to be apportioned by customer class according to each class's share of the utility's overall load.

They also call for retail electric providers (REPs) to be certified by the PUC and for aggregators, generators and power marketers to be registered with the commission. REPs affiliated with a utility may not participate in the pilot program within that utility's area.

The negotiating committee failed to reach agreement on two issues, however. One was whether to allow a utility the option to use a process to identify customers interested in the pilot, followed by a lottery, to select participants in the residential customer class. The second issue involved how to set nonbypassable "wires" charges if the PUC has not set interim rates by May 2001.

Utah: In 1998 the Utah Public Service Commission concluded that the market power of PacifiCorp was so pervasive that deregulation would have little effect. The PSC made its comments in a 30-page analysis to the Utah Legislative Task Force on Deregulation and Restructuring. There has been no significant restructuring activity in Utah since then.

Vermont: Central Vermont Public Service and Green Mountain Power have proposed to the Vermont Public Service Board that retail choice begin in the state in September 2001, saying the almost two-year delay would give them time to renegotiate supply contracts with Hydro-Quebec and local independent power groups and reduce stranded costs.

In March 1999, the two utilities issued an outline for restructuring in Vermont which called for competition to start in early 2000, but since then they have been unable to buy down high cost contracts with Hydro-Quebec and local independent power producers.

In the case of Hydro-Quebec, Senator Jim Jeffords recently failed in an attempt to force a deal by threatening to void the power sales contracts and it is unclear when talks will move ahead.

For the local IPP contracts, the utilities are pursuing a separate case before the PSB to get costs reduced by administrative action. And in October, the Vermont utilities selected AmerGen to buy the Vermont Yankee nuclear plant – the largest generation asset in the state. But that deal will also not be completed until later in 2000.

In a new restructuring proposal, filed with the PSB November 23, 1999, the two utilities said they would voluntarily give up their generation supply obligations and become wires only companies with exclusive rights to provide service to their existing franchise areas.

They proposed that the PSB certify energy marketers in the state and subject them to several conditions including a renewables portfolio standard and air emissions limits. They also recommended that the PSB handle procurement of default and standard offer service.

At the same time they said the PSB should hold a series of workshops on key issues to work out detailed rules based on input from all parties.

CVPS attorney Morris Silver, said the plan was a "careful and prudent approach to customer choice" which would provide time to settle stranded cost issues well in advance of final PSB decisions on rates.

The utility proposal is designed to be implemented by the PSB alone without the need for legislative approval – a tactic aimed at circumventing objections to restructuring by key members of the Vermont House of Representatives who blocked earlier proposals. But utility officials also said they would also welcome legislative support for the plan.

Virginia: In 1999, Governor James Gilmore signed into law the Electric Utility Restructuring Act of 1999, detailing the planned transition to a mostly deregulated retail power market. Virginia's formal transition to full retail competition will commence in January 2002 and all customers in the state will have the right to choose their supplier by January 2004. Virginia State Corporation Commission (SCC) has been working with two of its largest investor-owned electric utilities and a cooperative utility to design and implement retail pilot programs that will eventually grow into full retail customer choice for the utilities' customers.

On April 28, 2000, the SCC approved plans for what will be one of the nation's largest retail pilots ever, Virginia Power's "Project Customer Choice" which will include 71,000 customers by January 2001. In stage one, 35,500 Virginia Power customers in the Richmond area will be able to choose alternative suppliers beginning September 1, 2000. Another 35,500 in northern Virginia will have the same opportunity beginning January 1, 2002.

In its ruling, the SCC said that the pilot is "large enough to attract competitive suppliers yet manageable enough to avoid administrative pitfalls."

In a twist from pilots in some other states, the SCC said it will only count toward the 71,000-customer cap those customers who actually select an alternative supplier. Those who are selected to be part of the pilot but decide to stay with Virginia Power will not be counted toward the pilot limit.

Virginia's State Corporation Commission has set the annualized generation prices that alternative suppliers must beat to provide savings to pilot participants range from 3.457 cents/kWh for large industrial customers to 4.766 cents/kWh for residential customers. Concerns still remain, however, about the level of alternative-supplier participation even though the "prices to compare" were set higher than expected by the SCC.

Meanwhile, a Virginia Power spokesman said the utility is pleased by the responses so far to its marketing campaign to lure retail customers in the Richmond area into the pilot. So far 9,900 customers have signed up, including 8,755 residential customers, 890 small commercial customers and 255 large commercial and industrial customers.

The utility spokesman said the largest response has been to a direct-mail campaign, and that he expects still more sign-ups from that, and another burst of interest when alternative suppliers begin marketing campaigns of their own this summer.

Starting October 1, 2000, some 8,000 American Electric Power customers in Virginia will be allowed to select alternative electric suppliers under its retail pilot plan. Another 8,000 AEP-Virginia customer will be able to do the same starting on March 1, 2001. Each of the two phases of the pilot will involve 125 MW, or about 5% of AEP's Virginia load.

The SCC said that any customer within the Virginia service territory of AEP will be eligible to enroll in the pilot program. That is different from the Virginia Power pilot, which is limited to the Richmond area in its first phase and the northern Virginia area in its second phase.

The commission said that within a few months AEP-Virginia will supply the details of how customers will be able to enroll. Enrollment will be a measured by the number of customers, or load, that actually sign-up with a competing supplier. Customers who volunteer for the pilot but then decide not to switch will not be counted against the total number of customers eligible to select a competing supplier.

As it did for the Virginia Power pilot, the SCC will establish the "prices to compare" for the AEP pilot about two months before the pilot begins. The projected market price for generation will be determined by considering prices at five nearby trading hubs, and by calculating an average of the prices at the two hubs with the highest prices.

The SCC still must rule on a much smaller retail pilot proposed by Rappahannock Electric Cooperative of Fredricksburg, Va. Unlike AEP and Virginia Power, the co-op was not required to propose a pilot but decided to do so to gain experience with customer choice.

Washington: There has been no electric industry restructuring activity in Washington in the last 12 months.

West Virginia: By order issued January 28, 2000, in Case No. 98-0452-E-GI, the West Virginia Public Service Commission adopted, and recommended for legislative approval, a plan whereby users of electricity in the State would have open access, across existing and new utility delivery systems, to a competitive market for power supply.

On March 11, 2000, the West Virginia Legislature adopted this plan in to law. Although the plan is comprehensive in detail, it contemplates a series of rules that must be adopted by the Commission, both prior and after the implementation of customer choice.

On March 14, 2000, the West Virginia Public Service Commission issued a Notice of Proposed Rulemaking. The rulemakings addressed in the Notice must be completed prior to the starting date of competition, January 1, 2002. The rulemakings included 1) Interconnection standards; 2) licensing for power suppliers; 3) emergency service rules; 4) code of conduct; and 5) consumer protection.

The Notice set out the following schedule for completion of the rulemakings:

May 1, 2000 .... Initial comments due in response to the Notice

August 1, 2000 .... Commission issuance of proposed rules

September 30, 2000 .... Comment to proposed rules due

October 2000 .... Hearing to be scheduled by further order, if necessary

December, 2000 .... Commission issuance of final rules.

Wisconsin: Wisconsin Public Service Corp. has announced it hopes to jump start the development of a competitive generation market in Wisconsin by transferring its wholly-owned generating units into a separate non-regulated generating company.

While there is currently no serious action toward restructuring Wisconsin's electric industry, WPS believes efforts should begin to move in that direction.

"In moving toward a competitive environment, other states have forced their utilities to sell off their generation component," said Larry Weyers, WPS chairman and CEO. "Those plants get bought up by the big national companies. If that happens here, I don't see how Wisconsin energy companies can survive as anything more than bit players in the new industry."

WPS has 1,200 MW of capacity, principally made up of the six-unit, 360 MW Pulliam plant, the three-unit, 490 MW Weston Plant and five gas-fired peaking units representing 230 MW.

In its proposal, which WPS expects to file with the Wisconsin Public Service Commission in August, the utility states it will buy back the power under long-term contracts. It defers to the commission, however, to set the term of the power purchase agreements.

WPS said its proposal is only meaningful if existing utilities do not build new generation. New energy demands in Wisconsin would be met by the unregulated gencos and independent developers constructing new plants. "We must create a level playing field in which existing Wisconsin energy companies (not as regulated utilities) can compete with IPPs,"

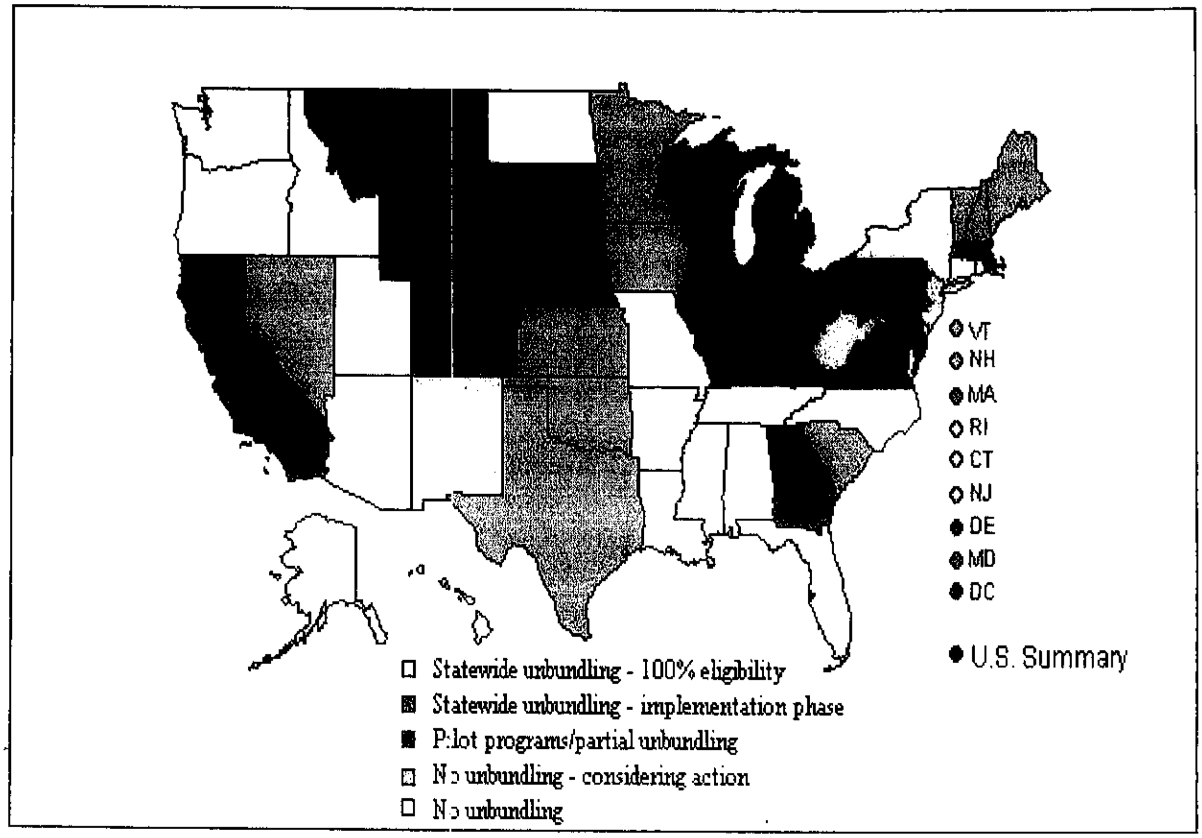
The move seems to be garnering support from both sides of the political spectrum. Democratic state Sen. Roger Breske, a senior member of the Senate Utilities Committee, called on the PSC to give it serious consideration. He also said he would push for a thorough review of the proposal by the Senate Utilities Committee.

Assembly Speaker Scott Jensen, a Republican, said the proposal deserves consideration by lawmakers and the PSC.

With its proviso that regulated utilities refrain from building new generation in Wisconsin, the WPS idea stands in opposition to Alliant Energy's April 25, 2000, initiative to construct a 600 MW, rate-based plant in the state. That initiative has come under intense criticism by independent developers who charge that it subverts competitive bidding for incremental wholesale power facilities in Wisconsin.

Wyoming: There has been no electric industry restructuring activity in Wyoming in the last 12 months.

Natural Gas Industry Residential Pilot Programs & Unbundling Initiatives



Residential Natural Gas Restructuring Status	States
Statewide unbundling – 100 percent eligibility	NJ, NM, NY, WV
Statewide unbundling – implementation phase	CA, CO, GA, MD, MA, OH, PA
Pilot programs/partial unbundling	DC, DE, IL, IN, KY, MI, MT, NE, SD, VA, WI, WY
No unbundling – considering action	IA, KS, ME, MN, NV, NH, OK, SC, TX, VT
No unbundling	AK, AL, AR, AZ, CT, FL, HI, ID, LA, MS, MO, NC, ND, OR, RI, TN, UT, WA

Source: http://eia.gov/oil_gas/natural_gas/restructure/restructure.html

Alabama

The Commission has approved the unbundling of services for large commercial and industrial customers. Residential customers do not have the option of receiving unbundled services. In 1998, the Commission opened an investigation into electric restructuring and has included natural gas issues as a part of the investigation. In 1999, the investigation is ongoing and continues to address major issues for both electric and natural gas unbundling.

Arizona

On January 5th, the commission voted to postpone the beginning of competition. Arizona Public Service (APS), Tucson Electric Power (TEP), and the Arizona Corporation Commission (ACC) are embroiled in settlement discussions over the companies' right to recover stranded cost, which have brought them before the Arizona Supreme Court. The electric unbundling of utilities' rates is in the near future but numerous details remain unresolved. This summer may bring a close to the settlement discussions and a new open access date.

2/4/99 Discussions are continuing among the parties. A meeting will be held today with APS and tomorrow with TEP. Resolution of the stranded cost issue is not expected to occur this week, and discussions probably will continue next week.

Colorado

Colorado Senate passed a bill to unbundle the gas market on the retail level and now it moves on to the state House of Representatives. The bill calls for at least five non-regulated suppliers in a service area to ensure open competition and allows utilities to recover transition costs. It also directs the PUC to conduct a study of the effects of market restructuring on low-income consumers.

Connecticut

In March 1999, the Connecticut Department of Public Utility Control issued order 95-02-07 allowing firm transportation service for commercial and industrial customer with 500 mcf or less a year. The commission continues to host collaborative meetings on metering, billing, balancing and an acceptable framework for unbundled gas services.

Delaware

The Delaware Public Service Commission issued a final order requiring partial unbundling of natural gas services in May 1997. Customer choice was available for large commercial and industrial customers but has not been made possible for residential customers. Conectiv Power has petitioned the Commission to conduct a gas pilot program that includes 14,500 residential customers and would begin in November 1999. The Commission is set to hear customer choice proposals in the summer of 1999.

Florida

On February 16, 1999, the Public Service Commission staff, PSC, issued recommendations for the unbundling of the natural gas industry. The recommendations include the approval of Peoples Gas Firm Transportation Rider, FTR, by extending it two more years and continued activity in the unbundling of natural gas services.

Georgia

On April 27, 1999, the Commission issued an order notifying all customer who have not chosen a supplier that If they have not chosen one in the next 100 days one will be chosen for them. The random assignment process will equally assign customers to marketers who have not chosen a marketer by the end of the allocated time frame. AGL must provide written notice to all firm customers 45 days and 80 days prior to the assignment.

SB 215, enacted in April 1997, called for the unbundling of gas services by October 1998. On January 26, 1999, the Public Service Commission, PSC, approved a settlement between the PSC staff and Atlanta Gas Light (AGL). The settlement requires AGL to refund $14.5 million to its customers and reduce rates. Currently, there are 19 marketers registered to serve natural gas customers.

On May 18, 1999, the Commission approved random assignment of customers to marketers on August 11, 1999.

Illinois

Industrial and large commercial customers have been choosing their own gas supplier since 1983. A selected amount of residential and small business customers have had the opportunity to make that same choice but through pilot programs. The commission approved pilot programs for Peoples Gas Light & Coke, Central Illinois Light, and Northern Illinois Gas. All the pilot programs have proved to be successful with high participation from marketers, residents, and the small business communities. This proof was presented to the legislators by the commission but there has not been any action on the issue, seeing as that the main focus of the legislature has been electric restructuring rather than natural gas restructuring.

Indiana

Natural gas restructuring in Indiana is moving slowly. In 1995, the Indiana General Assembly enacted SB 637. This piece of legislation granted authority to the Indiana Utility Regulatory Commission to adopt company-specific gas pilot programs. Currently, 19,000 customers (residential and commercial) in Northern Indiana Public Service Company's (NIPSCO) service territory are participating in the pilot. This number is relatively small, considering 102,000 customers (residential and commercial) are actually eligible to participate. The Commission determined, after review of NIPSCO's pilot, that all NIPSCO customers will have phased-in full retail access by December 31, 2004. The Commission has also issued orders that unbundle transportation and storage for large industrial and commercial customers.

Iowa

In 1998 the Iowa Utilities Board announced that it would start accepting natural gas restructuring plans, as a result all the utilities in the state filed there separate unbundling plans. The plans were so diverse that none of the parties could come to an agreement, therefore the board decided to dismiss the idea and instead ask the utilities to propose and file a designed tariff that would enhance natural gas competition. The board has not acted on those proposals. But the utilities requested the board conducted workshops and the various issues involving restructuring, unbundling, and retail competition. A decision from the Iowa Utilities Board is expected in 2000.

Kansas

On February 10, 1999, the commission initiated an investigation into retail gas unbundling. The staff intends to examine retail choice for small customers; performance rate making; and competitive bidding. A report is expected by May 1999. The Commission opened an investigation into gas unbundling in February 1999 and set a deadline of April 12, 1999 for comments in the matter.

Kentucky

The Gas Collaborative Forum created by the Kentucky Public Service Commission in 1997 and legislation introduced in the House in 1998 have both failed to render any progress on restructuring the Kentucky natural gas industry. However, in January, 2000, the Commission approved a 5-year pilot project for Columbia of Gas customers with an annual usage of less than 25 mcf. Customers who exceed this usage limit have enjoyed unbundled rates since the '80s.

Maryland

On May 4, 1999, the Commission approved Baltimore Gas and Electric's (BGE) proposal for customer choice for all customer classes. Commercial and Industrial customers are offered customer choice but a formal deadline has been set to completely unbundle natural gas for all customer classes.

Massachusetts

On March 31, 1999, the Massachusetts Department of Telecommunications and Energy (DTE) approved a settlement within DTE docket 98-32, Unbundling of Natural Gas Local Distribution Company (LDC) Services. The parties, ten IOU's, marketers, Attorney General and the Division of Energy agree to resolve certain issues relating to mandatory assignment of capacity to customers according to the DTE's 2-1-99 order, 98-32-B. The settlement does not address issues relating to the final policies and terms and conditions that will enable customers to access the resource portfolios of the LDCs.

Michigan

The Michigan Public Service Commission began a phase-in pilot for Consumers Energy customers. At this time, 176,000 of the eligible 300,000 customers are participating. Beginning April 1, 1998, and lasting for 3 years, distribution rates were frozen for all customers. The Commission has also approved a pilot program for Michigan Consolidated Gas customers in 1999. SEMCO Energy Gas and Michigan Gas Utilities have initiated three- and two-year pilot programs, respectively. Gas programs for large industrial customers have been in place since the mid-'80s. In 1999, legislation to restructure the gas industry for all customers by April 1, 2004 was introduced in the Michigan House of Representatives. This legislation is pending action by the House.

Minnesota

Large customers have been permitted to purchase their gas service from competitive suppliers for a number of years. The commission started an investigation in May 1999 on the issues of unbundling, retail choice, and restructuring in the gas and electric industries. The commission directed the Department of Commerce to develop a statewide program for natural gas restructuring by January 2001 to present to the 2001 legislative session. The PUC also established a separate another investigation on the issue of outsourcing gas and transportation procurement functions.

Missouri

Industrial and commercial customers have been able to receive transportation-only unbundled service since 1986. LDCs still provide meter reading, billing, maintenance, and other ancillary service. The Missouri Public Service Commission is conducting roundtable discussions on gas restructuring issues, but there are no proceedings in place to give residential and small commercial customers options of retail choice at the commission or the in state legislature.

New Jersey

The Board of Public Utilities (BPU) issued an order requiring gas utilities to file unbundled rate schedules by April 30, 1999. The March 17 th order requires that the filing include gas supply rates, billing credits, benefit charges, asset charge and transportation rates. SB 7, enacted in February 1999, requires all customers to have a choice of gas suppliers by December 31, 1999.

New York

Natural gas restructuring was enacted in 1985 giving large industrial and commercial customers the option of choosing an alternate supplier. In 1996 residential and small commercial customers became eligible to choose an alternate supplier for their natural gas services. The commission has composed statewide rules and regulations for the unbundling process. There are approximately 75 marketers registered in New York and at the end of 1999 17% of the non-residential customers exercised their option and 3% of the residential customers choose an alternate supplier. The commission is looking at outsourcing metering and billing services for customers.

Ohio

In 1998, the Ohio Public Utility Commission approved the expansion of gas retail choice programs that were in existence for three gas utilities: Cincinnati Gas & Electric (CG&E), East Ohio Gas (EOG), and Columbia Gas of Ohio (CGO). All residential and small commercial customers of CG&E and CGO are eligible to participate in the existing pilot programs. CGO will be able to recover 89% of its transition costs (16% through gas marketers and 73% through its recovery mechanism). In 1999, Columbia Energy Services announced the sale of its wholesale marketing operations to Enron North America.

Pennsylvania

Legislation signed into law in June, 1999 will permit retail customers to choose their gas suppliers beginning November 1, 1999.

Virginia

On March 27, 1999, the Legislature enacted SB 1105, which requires Local Distribution Companies (LDC's) to file retail customer choice plans with the State Corporation Commission (SCC). Each plan should include the following:

Implementation plans for all customer classes, beginning July 1, 2000; Open access tariffs for transportation systems; Provisions for the recovery of non-discriminatory stranded cost; Capacity release provisions; Affiliate Rules; and other provisions that the SCC deems necessary.

Source: http://www.ees.enron.com/choice/allstates_gas.html

Mergers Filed With The Federal Energy Regulatory Commission Since 1997

Docket No.	Principal Merging Entities	Status	Order Issued
EC97-5-000	Ohio Edison Company Centerior	Approved	10/29/97
EC97-7-000	Atlantic City Electric Company Delmarva Power & Light Company	Approved	7/30/97
EC97-12-000	San Diego Gas & Electric Company Enova Energy, Inc.	Approved	6/25/97
EC97-13-000	Duke Power Company PanEnergy Corporation	Approved	5/28/97
EC97-19-000	Long Island Lighting Company Brooklyn Union Gas Company	Approved	7/16/97
EC97-20-000	Destec Energy, Inc. NGC Corporation	Approved	6/25/97
EC97-22-000	PG&E Corporation Valero Energy Corporation	Approved	7/16/97
EC97-23-000	Morgan Stanley Capital Group, Inc. Dean Witter, Discover & Co.	Approved	4/30/97
EC97-24-000	NorAm Energy Service, Inc. Houston Industries, Inc.	Approved	7/30/97
EC97-46-000	Allegheny Energy, Inc. DOE, Inc.	Terminated	3/22/99
EC97-56-000	Western Resources, Inc. Kansas City Power & Light Company	Hearing	3/31/99
EC98-2-000	Louisville Gas & Electric Company Kentucky Utilities Company	Approved	3/27/98
EC98-7-000	Salomon Inc. (Phibro) Travelers Group, Inc.	Approved	11/26/97
EC98-8-000	Wisconsin Energy Corporation, Inc. Edison Sault Electric Company	Approved	4/22/98
EC98-23-000	Duke Energy Corporation Nantahala Power & Light Company	Approved	6/1/98
EC98-27-000	WPS Resources Corporation Upper Peninsula Energy Corporation	Approved	5/27/98
EC98-40-000	American Electric Power Company Central and Southwest	Conditionally Approved	3/15/00
EC98-62-000	Consolidated Edison Company of New York, Inc. Orange and Rockland Utilities, Inc.	Approved	1/27/99
EC98-63-000	MidAmerican Energy Holdings Company CalEnergy Company, Inc.	Approved	12/16/98
EC99-1-000	Sierra Pacific Power Company Nevada Power Company	Approved	4/15/99
EC99-33-000	BEC Energy Commonwealth Energy System	Approved	7/1/99
EC99-40-000	CICORP Inc. AES Corporation	Approved	6/16/99
EC99-48-000	Sempra Energy KN Energy, Inc.	Withdrawn	N/A
EC99-49-000	New England Electric System National Grid Group plc	Approved	6/16/99
EC99-50-000	PacifiCorp Scottish Power plc	Approved	6/16/99
EC99-70-000	New England Electric System Eastern Utilities Associates	Approved	9/29/99

Docket No.	Principal Merging Entities	Status	Order Issued
EC99-73-000	El Paso Energy Corporation Sonat Inc.	Approved	9/29/99
EC99-81-000	Dominion Resources, Inc. Consolidated Natural Gas Company	Approved	11/10/99
EC99-99-000	Illinova Corp Dynegy, Inc.	Approved	11/10/99
EC99-101-000	Northern States Power Co. (Minn.) New Century Energies, Inc.	Approved	1/12/00
EC99-106-000	SIGCORP Indiana Energy, Inc.	Approved	12/20/99
EC99-109-000	Pennsylvania Enterprises Southern Union Co.	Approved	11/01/99
EC00-001-000	Energy East Corp. CMP Group, Inc.	Approved	4/3/00
EC00-026-000	Commonwealth Edison Co. PECO Energy Co.	Approved	4/12/00
EC00-027-000	UtiliCorp United, Inc. St. Joseph Light & Power Company	Pending	N/A
EC00-028-000	UtiliCorp United, Inc. The Empire District Electric Company	Pending	N/A
EC00-049-000	Consolidated Edison, Inc. Northeast Utilities	Approved	6/1/00
EC00-055-000	Florida Progress Corporation CP&L Energy, Inc.	Approved	7/12/00
EC00-063-000	Sierra Pacific Power Company Nevada Power Company Portland General Electric	Pending	N/A
EC00-066-000	Consolidate Water Power Company Stora Enso Oyj	Approved	6/15/00
EC00-067-000	PowerGen plc LG&E Energy Corporation	Approved	6/29/00
EC00-070-000	Interstate Power Company IES Utilities, Inc.	Approved	7/7/00
EC00-073-000	El Paso Energy Corporation Coastal Corporation	Pending	N/A
EC00-075-000	NiSource Inc. Columbia Energy Group	Pending	N/A
EC00-076-000	Indeck Capital, Inc. Black Hills Corporation	Approved	6/16/00
EC00-106-000	Entergy Power Marketing Corp. Koch Energy Trading, Inc.	Pending	N/A

Source: Federal Energy Regulatory Commission website, http://www.ferc.fed.us/electric/mergers/mrgrpag.htm#MergerList